Distribution Engineering Reference Manual

Section 1 – General
Section 2 – Distribution Design Theory

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1.2 CONTRACT WORK

A. FPL LABOR UNITS - OVERHEAD DISTRIBUTION

The basis of the "Unit Cost" is the FPL Labor Unit, established after considerable research, involving many "on the job" time studies.

The amount paid to the contractor for any labor operation his employees perform on the construction job is based on the manhour value assigned to that particular "Labor Unit", multiplied by a labor rate multiplier. The labor unit includes productive on-site functions and operations, (to include loading of major material while at headquarters or at a remote storage area). It includes time for set-up, paperwork, instruction, etc., and an allowance for personal time. The labor unit value does not include time spent in headquarters, travel, or delay, or overhead and profit. The multiplier the contractor used on his bid must cover these latter items and all other costs.

For a list of Overhead Distribution Labor Units, click on the “Manuals” (Distribution Manuals & Procedures) link located in the “Reference Information” section on the Power Systems home page on the FPL intranet. This list describes the labor operation, assigns it a 6 digit number and a unit value in manhours.

The labor unit values represent the "should take" time to perform labor functions while using prescribed methods and working under existing conditions at a normal pace. The unit value varies, depending on whether the labor unit is to install, scrap, return, or transfer, and also whether the work is on energized or de-energized lines.

1. WMS “On” (Energized) Units

In general, this class covers all labor units performed on energized devices. The "due care" (extra caution) required for working in close proximity to energized facilities is reflected in the "On" labor values. This class reflects the time required to install, scrap, return, or transfer items of material or perform labor functions on energized lines and equipment. Included is the hands on or "gloving" of primary conductors and the handling of energized conductors and devices from secondary voltage through 13.2 kV (7.6 kV to ground).

23kV Units have been developed to reflect work unique to 23 kV application. The "Off" value is the same as the "Off" value for other uses. The "On" value includes the time to rig, install and remove protective devices and the "due care" for this work procedure. The 23 kV units are appropriate only for 23 kV (13.2 kV phase to ground) or any primary work above 23 kV.

2. Class "Off" (Cold) Units

Class “Off” covers all labor units performed on de-energized primary or secondary circuits that are tested to be de-energized and grounded out in the prescribed manner per accepted Safe Work Practices. This class also includes construction of new facilities, excavation of pole and anchor holes, installing or removing anchors, and installing ground rods, by machine.

3. Site Conditions

a. Inaccessible Locations

When a work location is not accessible to powered vehicles or equipment, a 43% urban and 18% suburban increase applies to certain units. These units are install, scrap, return, or transfer units for poles, anchors, timbers, platforms, transformers, capacitor banks, regulators, reclosers and conductors.

b. Swamp

For marshy or low lying area which is saturated with water and not accessible to normal powered vehicles or equipment, a 50% increase is allowed for most units.

c. Approval of Adders

For contracted work, the preceding adders are applicable with concurrence of contractor and FPL representative at each work location. Concurrence must be reached before commencing any involved work.

d. Adders For Overhead work

Adders are applied to the labor units by adding a complexity factor to the work request.

e. Overhead Labor Unit Definitions and Values

Overhead labor units are described and their values shown in the Labor Units Manual, as follows:

Excavation	-	Labor Unit Manual
Poles	-	Labor Unit Manual
Anchors Guys	-	Labor Unit Manual
Bonding & Grounding	-	Labor Unit Manual
Cross Arms	-	Labor Unit Manual
Brackets & Insulators	-	Labor Unit Manual
Cable/Conductors	-	Labor Unit Manual
Attachments & Connections	-	Labor Unit Manual
Conductor Appurtenances	-	Labor Unit Manual
Switches & Arresters	-	Labor Unit Manual
Transformers, Capacitors, Regulators & Reclosers	-	Labor Unit Manual
Street Lighting	-	Labor Unit Manual
Operations & Other Units	-	Labor Unit Manual
FPL Only	-	Labor Unit Manual
Contractors Only	-	Labor Unit Manual
Illustrations	-	Labor Unit Manual
Labor Unit Valueand Adder Code	-	Labor Unit Manual

B. FPL LABOR UNITS - UNDERGROUND DISTRIBUTION

1. Description of Units

For a list of Underground Distribution Labor Units, see your distribution construction services analyst. This list describes the labor operation, assigns it a 6 digit number and a unit value in manhours. They were prepared on the same basis as the overhead units previously described. They represent "should take" time for productive, on-site functions.

2. Purchase Units

Purchase units are set up to identify costs of a job not covered by labor or M&S items, such as ready-mix concrete, sod, backfill, etc.

3. Material

Material authorized and used on a job which is not available through stores is paid for at invoice cost plus a percent markup for handling and administration, typically 10 to 15%. This handling cost is not appropriate when items are available on an existing Blanket Purchase Order or are obtained from the same contractor who is executing the Work Request on an existing cost- plus contract.

Material for a job will normally be located at one storeroom designated when the job is released. If special conditions exist regarding material for a job, these conditions must be stated and understood.

If material is not available as specified in the job instructions, the material must be made available on a timely basis or the contractor reimbursed for additional travel or job delay. This delay, when authorized, shows as "Miscellaneous Labor (004-894)" on the job.

4. Lost Time

The contractor is reimbursed for lost time on a job when he has completed all productive portions of a job he may work on, but is held up from completing the job by the customer, the builder, or by FPL. The lost time is authorized by the FPL representative in writing (or in CAMS), and shown as a non-unit time adder on the Non Unit Time (NUT) form. This form becomes part of the job files.

5. Special Handling

On reimbursable jobs, the handling of the reimbursable material is compensated by a 10% increase in the removed "Off" value total labor. It becomes part of the job papers by memo and enters the system by the Miscellaneous Labor unit (004-899).

6. Inaccessible Locations

When a work location is not accessible to powered vehicles or equipment, a 25% urban and suburban increase applies to certain units.

7. Labor Class Codes

The "On" value represents either labor functions performed by hand or on an energized device.

8. Trenches

1. Service trench is defined as a short non-continuous trench from property lot corner to the customers point of service.
2. Backbone trench is generally long continuous runs of trench and all other trench not defined as street light or service trench. Backbone trench units may be (1) Machine trench up to 10 inches width or (2) Machine trench greater than 10 inches width up to 18 inches. If wider trenches are needed, add the appropriate trench values together to get the desired width. Show on an as-built sketch for affected location.

9. Labor Unit Definitions and Values

The appropriate labor units and values can be located as follows:

Trench and Backfill	-	Labor Unit Manual
Conduit and Cable Pulling	-	Labor Unit Manual
Pads, Handhole & Accessories	-	Labor Unit Manual
Risers	-	Labor Unit Manual
Transformers & Switches	-	Labor Unit Manual
Primary Connections	-	Labor Unit Manual
Secondary Connections	-	Labor Unit Manual
Miscellaneous	-	Labor Unit Manual

FPL Only	-	Labor Unit Manual
Contractors Only	-	Labor Unit Manual
Labor Unit Value & Adder Codes	-	Labor Unit Manual

C. THE COMPANY REPRESENTATIVE

The name and work location of the company representative is included in the purchase order.

The FPL manager or department head in charge of the work appoints the FPL representative. At the manager's discretion, he may have the FPL representative also be the FPL Inventory Representative, or he may appoint another individual to perform the duties of the inventory representative.

It is the responsibility of the company representative to see that the work invoiced has been authorized and completed before he prepares a receiving report to pay the contractor's final invoice. He must also see that the job sketch and other instructions are changed, if necessary, to reflect "as built" conditions.

D. MAKING THE ENGINEERING ESTIMATE FOR LABOR

The engineer must first lay out his job on paper, showing by means of standard DCS A3-A11 what construction the work request will authorize. He should note unusual conditions which would affect labor costs, such as accessibility, marsh or swamp conditions, rocky ground, etc.

When the WMS inventory is made, these conditions are entered, since they affect the labor unit cost which will be attached to the WMS construction unit. This is done, of course, whether or not the job is to be contracted. As a matter of fact, at the time the job is inventoried, the engineer does not know whether the job will be constructed by FPL crews or the contractor.

In planning the overall job, before getting into the specific details, it is well to consider the effect of "On" class work on the difficulty, and thus the cost of the job. There are occasionally cases where building a new line over a new route may be easier and less expensive using "Off" class labor unit than reconductoring and extending an existing line using "On" class labor units for many of the labor operations. The WMS estimating system may be used to generate numerous "cost only" estimates so that economic analysis can be performed.

The engineer should strive to include all the factors needed in his WMS inventory to enable the WMS estimating system to produce accurate estimates.

The company representative on the contracted job must approve the contractor's invoice before it can be paid. While there are contractor's multipliers and adders for authorized overtime and stand-by time, an accurate labor summary from the WMS estimate is the most important item in verification of the contractors invoice. A well engineered and WMS inventoried job will also reduce the number of job changes which the company representative will be asked to authorized.

E. CONTRACTING FOR SERVICES OTHER THAN T&D CONSTRUCTION

PRO Procedure #700 covers contracting for material and services. When contracting for professional or consulting services, the same procedures apply.

1.3 CONSTRUCTION DRAWINGS

A. GENERAL

Since the computer has become the principle tool for drafting, designers need both a general knowledge of drafting and a basic understanding of CAD (Computer Aided Drafting). This basic knowledge will be beneficial when communicating with the Technical Resource Services (TRS) department and outside firms in obtaining developer files for both underground residential and overhead (e.g., road widening projects). The objective of this manual will be to cover those drafting functions, which are directly related to the preparation of work orders and the successful completion of the associated construction. The designer performs some of these functions, either manually or by using software tools when job sketches are made from field notes. In other cases, CAD drafting is done in the TRS department.

B. THE CONSTRUCTION AND SCHEMATIC DRAWING

The construction and schematic drawings are the primary instruments used to communicate what work needs to be done in the field. The construction drawing conveys your design instructions to the crew and the crew supervisors. The schematic drawing conveys your design instructions to the trouble office personnel. Your drawings are not only used for the construction job but they also become the vehicle that other departments use to carry out their responsibilities (i.e., Cable Locate, TRS, Survey, Restoration). An example would be the Technical Resource Services (TRS) department utilizing construction drawing information to update the Asset Management System (AMS). Reference DERM 2.6.1. All drawings, both overhead and underground are to be sent to TRS for this AMS updating process.

Various types of drawings exist and FPL drawing standards are to be applied to all drawings. Refer to the Distribution Construction Standards book (DCS) section A for symbols and examples. Also see the TRS Web site, under Power Systems, in INFPL for additional information. From the TRS website home page select Cad Work Order/APD to find examples of the standard statewide construction and statewide schematic drawings.

Overhead jobs are usually drawn to FPL standards by Project Managers/Designers using Visio Software by at the service center. Refer to the Designers Aids, under the Distribution Construction Services web site, Power Systems in INFPL for templates used for designs.

C. FPL RECORD DRAWINGS

Construction jobs that install underground facilities must be given a record drawing number . These are typically drawn by TRS using Cad software referencing a marked up design package provided by the designer. All record drawings are to scale except for the schematic drawing. Record drawings can be viewed from your work station through the TRS Technical Information System (TIS). When creating a record drawing, TRS will provide: record drawing number, loop numbers if needed, coordinate with the Dispatch Center to obtain switch numbers if needed, create a schematic drawing from the construction drawing, make the required prints, send copies to the Project Manager, Cable Locate, Trouble Office, TRS AMS/Map posting, TRS Survey and generate TLM tags as required by the individual job.

The different types of record (underground) drawings are briefly discussed below.

URD/R/Pad/Radial type drawings are typically drawn in a plan view only. These drawings should encompass the scope of the work to graphically display or facilities locations in reference to streets, buildings, parking lots and road ways.

Plan & Profile type drawings are typically drawn for concrete incased duct bank systems and include location of the manholes connected to the duct runs. A profile view is provided to show the route of the duct bank and elevation in reference to other facilities.

Manhole drawings are drawn from a top view that show the vertical walls laid down on the same plane as the floor of the manhole. This allows for a clear view of the route cables take through the manhole. Additionally showing which ducts used or open, location of splices cable type and feeder identification.

Vault drawings vary greatly due to the space provided by the customer and the resulting floor plan of the vault. It also shows the route of the feeder cable as it enters the vault and passes through the various switch gear, transformers and through to the secondary bus bars.

D. BACKGROUNDS & DIMENSIONS ARE CRITICAL FOR DRAWINGS, AMS, & GIS

The key to a good design starts with having the best background possible. For example, site plans, plats, customer surveys, easement sketch and description, and right of way plans. These backgrounds have all the base measurements needed for your design (lots, blocks, road centerlines, right of ways) and they are scaled for precise measuring. Accurate backgrounds are required on all jobs (Overhead and Underground) in order to accurately display facility locations in AMS. Several different locations within your background must be "tied down" or given dimensions in two directions to major intersections and/or other know land marks in order to accurately place your job in FPL's Geographical Information System (GIS). Reference DERM 2.6.1.

Once the overall background has been "tied down" to surrounding land marks, you must then "tie down" (or give dimensions in two directions), to accurately reflect the location of FPL facilities (transformers, trench, etc.) to locations existing on the background. Dimensions off existing buildings, centerline of streets, property corners are good ways to ensure an accurate drawing and accurate posting of your job in AMS. It is also critical these "tie down" dimensions are on your drawing so the Survey department can stake your job for construction.

The precise information required to be on construction drawings varies greatly and much too complex to be able to give instructions here. This must be learned by working with other designers and using examples of their drawings. Just remember how very important the drawing is for communicating with the various people involved and take care to provide the needed information. The Distribution Construction Standards (DCS) provides much of the detailed information that the crew requires for construction. You should provide information on the drawing that tells the crew what to build and where to build it in a way that is definite and specific. Provide a small location sketch for all drawings. Also provide any cautionary notes needed to warn the crew about unusual conditions or customer's requirements.

Section 1.4 has not been updated since December 2000. Please refer to the on-line version for updates prior to using.
InFPL/Power Systems/Reliability/DEO/Publications/DERM

1.4 INDUSTRY CODES AND STANDARDS

There are two National Codes setting rules for the safe design, construction, and maintenance of electrical systems - from the generating station to the wall outlets in our homes. Neither code has any legal status in itself, but is given that status by authority of state, county, or municipal laws. These jurisdictional authorities may adopt none, all, or any part of the codes, and with or without changes.

The National Electrical Safety Code (NESC) deals, in general, with utilities - from generating station to the customer's connections. The National Electrical Code (NEC) deals, in general, with building inside wiring. We are careful to say "in general" because there are exceptions and overlaps. For instance, FPL substation switchyard design is based on the NESC, while the control house wiring (lights, air conditioning, sprinkler pump, etc.) design is based on the NEC.

By authority of the Florida Public Service Commission, FPL is subject to all the rules of the National Electrical Safety Code (American National Standards Institute, ANSI C2). Beginning July 1, 1986, the FPSC formed a "Bureau of Public Safety", whose mission it is to inspect our facilities built after that date, for compliance to the NESC. This code includes, but is not limited to, rules on grounding; conductor clearances, separations, and sags; strength of poles, crossarms, and hardware; tree trimming; buried cable depths; risers; etc.

An example of the interface between the two codes, is that a vault separated from the rest of a building by anything less than two inches of concrete is considered a room in the building, and inside wiring rules (NEC) prevail. If the separation is by more than two inches of concrete, it may be considered outside the building under the exclusive control of the utility -and NESC rules apply.

All applicable portions of the NESC are incorporated in the FPL Distribution Construction Standards. We sometimes exceed NESC minimum requirements where, in our judgement, it is justified to do so. For instance, due to the higher exposure to hurricanes in Florida, we design our overhead distribution lines with a stronger grade of construction than generally is required by the NESC.

Other agencies imposing their own requirements on electric utilities are the Department of Transportation, the Corps of Engineers, and Railroads, for installations over, under, or along their facilities. In case of a conflict between any of these agencies and the NESC, the more conservative rule shall take precedence.

Industry standards for material assist rather than restrain the utility engineer, since specifications are already written for commonly used material. Some of the most used are the American National Standards Institute (ANSI) specifications. We can order the common 5/8" X 10" machine bolt with no more description than "per ANSI C135.4" and know the type and size threads, the size and type head, how galvanized, that it comes complete with nut (which is also a part of that specification), the minimum strength, even the packaging. Our manufacturers are those who have satisfactorily demonstrated their capability and commitment to meet the requirements.

Some other organizations maintaining standards, rules, and specifications affecting the construction, operation and maintenance of an electric distribution system are:

- Institute of Electrical and Electronics Engineers (IEEE)
- Edison Electric Institute (EEI)
  - Association of Edison Illuminating Companies (AEIC)
  - American Society for Testing Materials (ASTM)
  - Insulated Cable Engineers Association (ICEA)
  - National Fire Protection Association (NFPA)
- National Electric Manufacturers Association (NEMA)
- National Bureau of Standards (NBS)

Whether or not covered by industry standards, it is sometimes necessary to test the mechanical or electrical characteristics of an item of material. For this purpose, FPL maintains its own test facility. Designs not available in the marketplace and designed in-house are also tested there.

The end results of our interpretations of the codes, industry standards, our own designs, and testing, are seen in FPL publications such as the Distribution Construction Standards, the Standard Material Catalog, Material Specifications, the DERM, the Electric Service Standards, etc.

2.1.2 DISTRIBUTION FEEDER COORDINATION

This section describes the characteristics of equipment employed in feeder fuse-breaker coordination, and how the system operates during temporary and permanent faults. This section points out that individuals responsible for feeder coordination must know the characteristics of the feeder thoroughly in order to arrive at a workable coordination scheme. This knowledge would include:

1. The feeder loading and any large spot loads requiring abnormally large fuses.
2. The value of the fault current at various locations on the feeder.
3. The characteristics of protective equipment.
4. The operating sequence of combinations of protective equipment.
5. The interrupting ratings of the protective equipment.
6. The characteristics of the feeder conductors in the circuit.
7. Calculation techniques for electrical network solutions.

With these factors and other knowledge gained, a well-coordinated distribution system can be designed which will protect components as well as limit the amount of circuit outage during times of abnormal conditions.

Most of the load served by Florida Power & Light Company is served from the Company's distribution system. With an extensive exposure to weather elements, vegetation and animals, the probability of damage to the conductor during an event can be very high. In order to reduce this probability and to maintain service continuity, it is necessary to design and operate a sophisticated protective scheme. The success of this scheme is dependent upon many factors. A few of the more important factors will be discussed here in general terms.

A. TYPE OF SYSTEM AFFECTING COORDINATION

1. Multigrounded Wye System
   a. Requires driven grounds at each pole that has a lightning arrester or transformers installed.
   b. The resistance of the driven ground shall be 25 Ohms or less.
   c. The NESC requires a driven ground not less than four grounds in each mile of the entire line, not including grounds at individual services.
2. Effectively Grounded Systems
   a. Industry Definition (IEEE Std 142-1.2.1)

      The ratio Xo/X_1 falls between 0 and +3.
      The ratio Ro/X_1 falls between 0 and +1.

      These ratios limit the maximum voltage rise on the un-faulted phases during a phase to ground fault to approximately 135% of normal.

   b. FPL Definition

      Voltage on un-faulted phases shall be less than 135% of normal during phase to ground faults at the substation.

3. Fault Current Limited System (REV 11-23-09 BY SC)

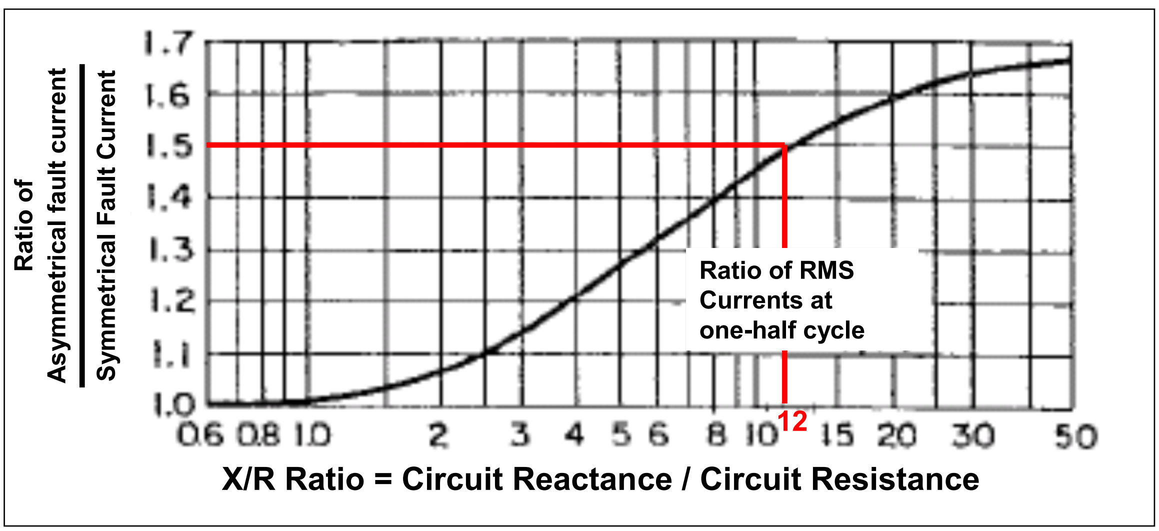
One of the most important fundamental principles to consider for a proper design of an electrical system is the need to safely carry large amounts of fault currents that are present in the system during short circuits. That is, in addition to its load current handling capability ratings, all electrical equipment requires a fault current rating capability as well in order to withstand large amounts of heat energy flow without damage to the equipment.

Distribution substation fault current limitation guideline:
13.2 KV and 22.9 KV feeders at the Pulloff will have a nominal design limit with the following requirements:

- Maximum Three Phase Fault Current = 6700 Amps Symmetrical
- Maximum Phase to Ground Fault Current = 4000 Amps Symmetrical
- Effectively Grounded System definition (IEEE Standard 142-1.2.1)
  The ratio Xo/X1 falls between 0 and +3; The ratio Ro/X1 falls between 0 and +1.
- Some underground and/or other types of specialty feeders may require further fault current limiting as specified by the Planning Dept, to ensure meeting the fault interrupting rating of the equipment on the feeder.
- Phase reactors (typical = 0.5 Ohms) are installed, if needed, to help limit the fault currents below this guideline. The phase-to-ground fault currents are typically limited by a 0.8 Ohm neutral reactor in the power transformer ground connection at 13kV substations or a 1.33 Ohm neutral reactor at 23kV substations.

Three Phase fault current limitation
During the original design of the Distribution System, the Fault Current Rating of Distribution Equipment was reviewed to ensure that faults would not exceed the rating of the equipment.
The OH Fuse Cutouts (Fault current rating = 10 kA asymmetrical) were the minimum limiting component.
The 3 phase symmetrical fault current level was estimated using an asymmetrical to symmetrical ratio of 1.5 (Based on X/R ratio of 12), or about 67% of the Fuse Cutouts asymmetrical rating: (See graph below)

Symmetrical 3 Phase Fault Current = 10,000 Amps (Asymmetrical rating of Fuse Cutouts) / 1.5 = 6,700 Amperes.



Phase to Ground Fault Current limitation:
Currents flowing during phase-to-ground faults at the substation pull-off are limited to below 4000 Amperes symmetrical. This is necessary in order to ensure proper coordination between our standard OH lateral fuses (65KS) and the Ground Instantaneous (Gi) relay.

4. Current Coordinated System

Protective devices are installed on the distribution circuits to:

a. Allow for passage of normal load currents.

b. Allow for interruption of abnormal (fault) currents.

c. Protect equipment from damage.

d. Minimize the amount of the circuit interrupted.

e. Distinguish between temporary and permanent faults.

f. Assist in faster restoration.

B. TYPES OF FAULTS

1. Phase-To-Ground Faults

The most common type fault experienced on an overhead distribution feeder is the phase-to-ground fault. These faults are often caused by:

a. Lightning

b. Vegetation

c. Animals

d. Equipment

e. Other contact

Currents can sometimes be very low if there is any impedance or resistance (dry ground, etc.) at the fault.

During the period of time the fault is on the circuit the voltages on the phases not involved in the fault may rise.

2. Phase-To-Phase Faults

These faults are not very common. Phase-to-phase faults can be caused by arcing that is initiated during switching or fuse-clearing. The ground or neutral path is not involved in this type of fault. A conducting path is established between two of the phases.

3. Phase-To-Phase-To-Ground Faults

This type of fault can occur on overhead circuits due to vegetation or during switching or fuse-clearing. These faults occur more often on U.R.D. circuits where single conductor cables are used on two-phase and three-phase circuits.

4. Three-Phase Faults

These type faults are more common on underground circuits that use three conductor cables. These faults very rarely occur on overhead lines.

C. CHARACTERISTICS OF FAULTS

1. Temporary Faults

a. Self-clearing faults are rarely on the circuit more than 1/2 cycle and may or may not cause protective equipment to operate. Experiments conducted during the 1960's revealed that Self-clearing faults usually have a magnitude of fault current below 2000 Amps.

b. Other temporary faults (not self-clearing) will be interrupted quickly by protective equipment. These faults are usually phase-to-ground type faults. If the circuit is successfully restored without a fault still present on the circuit the fault is considered to have been only "temporary".

2. Permanent Faults.

a. Unlike temporary faults, permanent faults do not disappear once the circuit is opened. The circuit cannot be re-energized without re-establishing the fault current. In order to protect equipment and conductors, the circuit should be interrupted as quickly as possible.

b. Restoration of the circuit after the occurrence of a permanent fault requires that the fault has to be located and the problem corrected before re-energizing.

D. OBJECTIVES OF COORDINATION

In the design of any coordination scheme there are certain objectives to be achieved.

1. The scheme should allow for carrying the expected load currents without unnecessary interruptions or outages due to slight overloads.
2. The scheme should not interrupt for self-clearing faults if at all possible.
3. The scheme should interrupt all non-self-clearing faults as quickly as possible.
4. The scheme should re-energize the circuit to test for temporary or permanent faults. (Temporary faults should not cause permanent outages.)
5. The scheme should allow for clearing of permanent faults by those interrupting devices nearest the fault.
6. The scheme should allow permanent outages on the smallest possible amount of circuit.

E. COORDINATION EQUIPMENT

In order to help meet the objectives of our coordinated system, we apply overcurrent devices operating in series with each other.

1. Substation Feeder Circuit Breakers

The breaker (OCB – Oil Circuit Breaker) is a heavy-duty interrupting device which controls the power required by the loads. All new FPL distribution feeder breakers are rated at 1200 Amperes. In order to clear temporary and permanent faults as quickly as possible, our substation feeder breakers should have a clearing time of 3 cycles or less.

2. Circuit Breaker Relays

These devices are used to control the operation of the breakers during fault conditions. The relays are connected to the primary circuit through current transformers. We are presently using six separate relays for tripping control; three phase relays (one in each phase) and three ground relays. An additional relay is used for reclosing the breaker. Prior to 1992, only electromechanical relays were used. In 1992, FPL began using microprocessor-based electronic relays for all new feeders installed and when replacement of electromechanical relays become necessary.

The tripping relays are connected in the circuit as follows:

c. Phase Relays (AT, BT, CT)

These relays will detect all types of faults. They will also have a time delay, the length of which is determined by an induction disc that rotates when current passes through the relay. The higher the magnitude of current the shorter the time delay. (The faster the disc moves.)

d. Ground Relays (GT, GX, GI)

These relays will detect only faults involving neutral or ground currents. The ground relays indicated GT and GX are time-delay relays similar to the phase relays. The GT relay is identical in style to the phase relay except the range of current taps is different. The GX relay has shorter time delay than the GT relay. The GT relay is normally referred to as the "long time delay" relay and the GX as the "short time delay" relay.

The GI relay is an instantaneous (no intentional time delay) operating device, and is usually an attachment to one of the ground time delay relays.

e. Reclosing Relays

These relays are used on the OCB to control the closing sequence and timing. The first closing is nearly instantaneous (0.4 sec.), the second one occurs 15 seconds after fault initiation and the third one occurs after 30 seconds. (The second and third relaying times are a function of the reclosing relay.) The third reclose may be controlled by SCADA while field implementation of the third reclose occurs.

3. Lateral fuses

Fuses are installed on all single and two-phase laterals. They will generally be type KS fuses which have an extra slow time-current characteristic. This type KS fuse will coordinate well with feeder breaker relays when properly sized. The majority of overhead laterals are fused with 65 Ampere fuses in 13kV areas and 65 Ampere fuses in 23kV areas. Fuse-to-fuse coordination on laterals is also part of a well-coordinated circuit. Underground laterals are fused with type K fuses.

4. Line Reclosers

(a) These devices are used on distribution circuits to extend the limit of protection and/or provide sectionalizing of feeder radials. As faults occur farther away from the substation, the magnitude of the fault current is reduced. In some cases these lower fault currents will not fall within the coordination limits of the substation feeder breaker relay. A recloser may then be recommended by the Reliability Planning Department.

The line recloser (OCR – Oil Circuit Recloser) is usually a light or a medium-duty interrupting device. Unlike breakers, reclosers do not usually have relays for tripping.

Line reclosers can automatically reclose after a fault in order to test the circuit for temporary faults. They come in various current ratings and single-phase or three-phase versions. Reclosers have time-current characteristics that allow the device to coordinate with breaker relays as well as type KS fuses. The fusing guideline mentioned above should be consulted for fusing laterals behind a recloser.

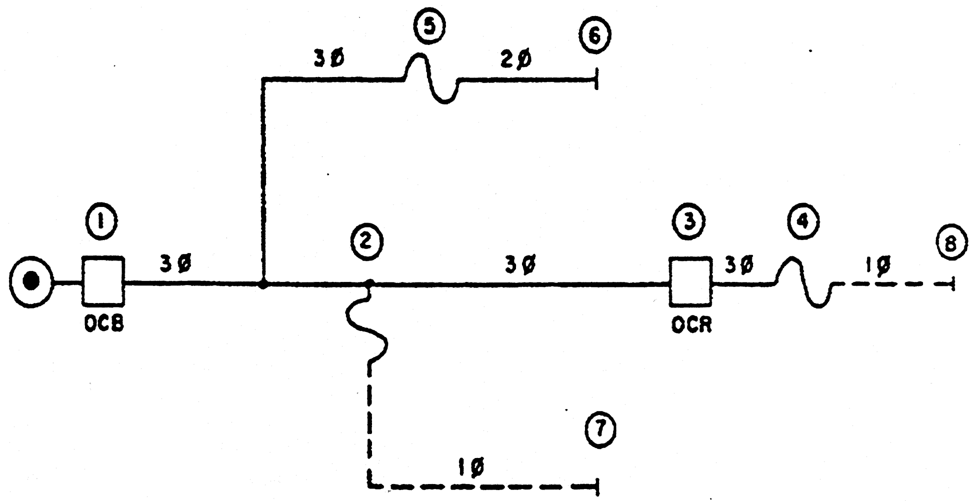
5. Line Sectionalizers

These sectionalizers are sometimes used to isolate permanently faulted lines. They are usually used in place of fuses. They are made in different current sizes and do not interrupt fault currents. They sense the fault current and count the number of times a back-up device (OCB or OCR) has operated and will trip open after a predetermined number of operations only when the back-up device has the circuit de-energized. Their application on our system is very limited.

F. THE COORDINATED SYSTEM

1. Representative Circuit

Current coordinated systems will have the various protective devices connected in series with one another. A distribution feeder will originate at the substation and the primary protective device will be the OCB. The OCB has current transformers to reduce the circuit fault current to a small value that will not damage the relays. Below is a representative, simplified circuit of a coordinated feeder:



For a well coordinated system, temporary faults anywhere on the circuit will cause a fast (or instantaneous) trip of either the OCB or the OCR, or both the OCB and the OCR. When these devices automatically reclose the fault should no longer be present, having been cleared with the opening of the device. This type of operation would be typical of a stroke of lightning causing a flash over on an insulator.

f. Permanent Faults

For permanent faults the operation of the protective devices will vary with the portion of the circuit experiencing the fault. If a permanent fault occurs on the three-phase circuit bounded by locations 1, 2, 3 and 5 only the station OCB will operate. The normal sequence of operations for a permanent phase-to-ground fault in this area is:

1. Fault is initiated.
2. The OCB is tripped by the GI or GX relay and clears the circuit in 3 to 8 cycles.
3. The OCB almost immediately recloses (0.4 sec.).
4. The OCB is tripped the second time by either of the phase relays or the GT relay (depending on the type of fault) in an amount of time characterized by the relay timing.
5. The OCB will reclose this time 15 seconds following fault initiation. (This reclose time is a function of the reclosing relay).
6. The OCB is tripped the third time by either of the phase relays or the GT relay (depending on the type of fault) in an amount of time characterized by the relay timing.
7. The OCB will reclose this time 30 seconds following fault initiation. (This reclose time is a function of the reclosing relay or SCADA).
8. After reclosing, the OCB will trip again similar to step number 4, above. After tripping (the fourth time) the reclosing relay will "lockout" and the OCB will not reclose again automatically, thus causing an outage and removing the faulted portion of feeder from the substation bus.

g. Permanent Phase-to-Ground Faults

For a fault of this type on the portion of single-phase lateral between locations 4 and 8, the following sequence should occur:

1. OCR will trip on its "fast" trip characteristic. (Whether or not the station OCB trips will depend on the coordination limits between the OCR "fast" trip curve and the OCB's GX relay.)
2. If the station OCB has tripped, it will reclose almost immediately (0.4 sec.).
3. Reclosing of the OCR is delayed and will vary from 1 to 2 seconds depending on the size and type of the OCR. After this delay the OCR will close.
4. If the fuse at location 4 is properly coordinated with the OCR, it should clear the circuit and cause an outage on only the single-phase lateral in section 4 to 8. No more OCR or OCB tripping should take place.

   In all instances of permanent faults on the load side of fuses, the fuse should clear the fault from the circuit and not cause "lockout" of any OCRs or OCB's in series ahead of it.

   In all instances of permanent faults on the load side of OCRs, where no fuse is in the circuit (section between 3 and 4), the OCR should go to "lock-out" and clear the circuit without causing "lock-out" on the station OCB.

G. TIME-CURRENT CHARACTERISTICS

To properly coordinate equipment on a distribution circuit, it is necessary to know the time characteristic of the device in relation to the magnitude of current. This information is usually displayed in log-log graph form with time-current curves. Samples of relay curves, fuse curves and recloser curves are included at the end of this section.

1. Relay curves.

These curves are plotted with "Time vs. Multiples of Minimum Closing Current" and consist of a family of curves representing the available "Time Dial" settings for the relay. Also shown on the curves are the available "Current Tap" settings for the relay. These two variables - Time Dial and Current Tap - give flexibility in coordinating relays with other devices such as fuses. (Figure 1, 2.1.2: 12 of 16)

2. Fuse curves.

These curves are plotted with "Time vs. Current" and give predictions of the amount of time that a particular fuse can withstand certain magnitudes of currents. Fuse curves consist of two curves per fuse which describe an operating band for the fuse. The lower curve is the "Minimum Melting" curve and indicates the time it takes for a certain magnitude of current to start melting the fuse element. For instance, at 1000 Amperes a 65 KS fuse starts to melt in approximately 0.65 seconds. If a 1000 Ampere fault current passes through a 65 KS fuse, damage to the fuse should not occur if another device, such as a relay, removes the fault in less than 0.65 seconds. The upper curve of the fuse is the total clearing curve and indicates the expected time it will take to "blow" the fuse for various current magnitudes. (Figure 2, 2.1.2: 13 of 16)

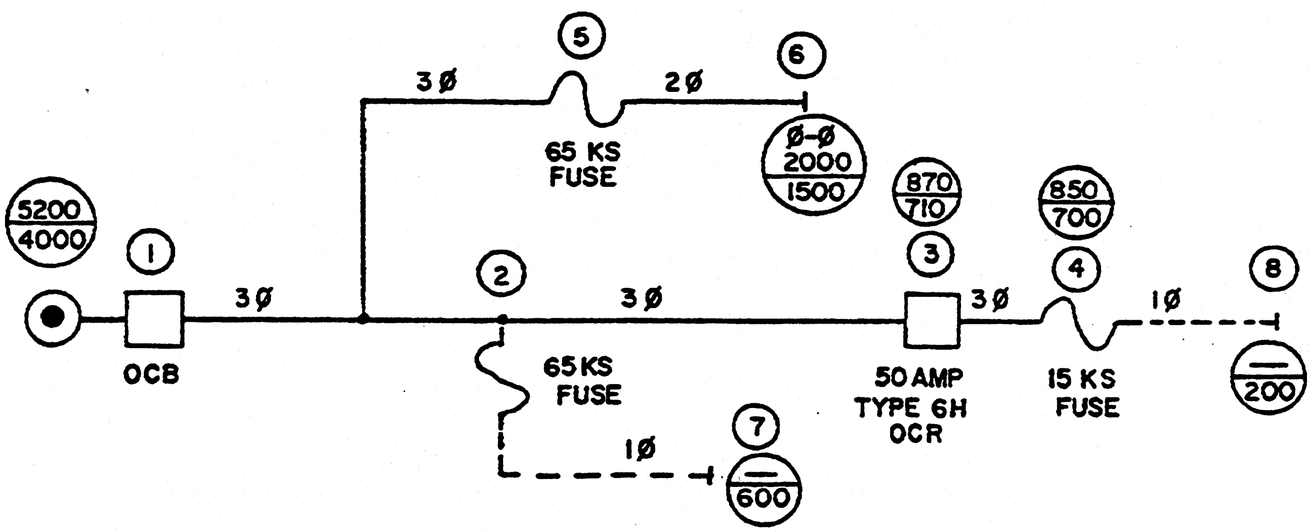
3. Line recloser curves.

These curves are plotted with "Time vs. Current in Multiples of Full Load Rating". The timing of tripping for reclosers is not as flexible as it is for relays, but there is still some latitude for coordination in the selection of the size of the recloser.

Since most recloser tripping currents are twice the full load rating of the recloser, sometimes it is possible to achieve desired coordination by selecting a different current rating OCR for a particular location. The lowest curve on the time-current grid represents the OCR fast trip characteristics; the middle curve represents the time-delayed trip; the top curve represents the lock out time of the OCR. The lock out time is a function of the number of fast plus the number of slow trips. Our most common sequence is one fast and two slow trips to lock out. (Figure 3, 2.1.2: 14 of 16)

H. COMPOSITE COORDINATION CURVES

To properly check the coordination of a distribution feeder, the Time-Current curves of the various protective devices are put together on one background grid. (An example is shown on Figure 4). From this composite it is possible to compare the timing of the different devices for particular fault currents. The representative, simplified circuit will also be used as an example. The circles that have been added contain the magnitude of three-phase, phase-to-phase and phase-to-ground fault currents at different locations along the circuit. Also, the OCR and the fuses have been given ratings.



1. Example.

Assume there is a single line-to-ground fault on the single-phase lateral at location 8 and also, assume a good, solid contact between the phase conductor and the neutral.

a. The magnitude of the fault current is 200 Amperes.

b. Following the circuit back toward the substation, there are three protective devices in series through which the fault current must flow. The OCB at location 1, the 50 Ampere OCR at location 3, and the 15 Ampere type KS fuse at location 4.

c. Looking at the composite Time-Current curves (Figure 4, 2.1.2: 15 of 16), the sequence of events that will clear the fault from the circuit can be determined. First, look at the 200 Ampere point on the current axis and follow it up the time axis. The first coordination curve is the OCR fast trip curve. This curve crosses the 200 Ampere line at approximately 0.16 seconds. The OCR can be expected to trip in that time frame. Knowing the characteristics of the OCR, it will likely reclose in 1 – 1.5 seconds and that the next tripping operation will be time delayed.

d. Looking again at the coordination curve, when the OCR recloses the 200 Ampere fault current will flow and the next protective device in the circuit, "time-wise", is the 15 Ampere KS fuse. At 200 Amperes it will begin to melt in 0.7 seconds and should clear the fault in 1.5 seconds. Once the fuse clears, the fault is permanently removed and an outage occurs on the line section between locations 4 and 8. The rest of the circuit will remain energized.

e. It should be noted on the Time-Current Curves that the fuse cleared in a shorter period than the time required to trip the OCR (1.5 seconds) on its slow curve so that the OCR should not take more than one trip.

f. Following the 200 Ampere line farther up the time axis, note that the OCB curves are not encountered; the curves are off to the right of the 200 Ampere line. This indicates that the OCB relay current pick-up value is above the fault current value and we can say that the OCB relays cannot "see" this magnitude of fault current.

2. Coordination Record

Time-Current Curves in conjunction with Coordination Diagrams (computer-generated maps showing expected fault currents at various locations) constitute a record of expected fault current ranges, expected operation of protective devices and proper lateral fusing. A complete feeder coordination record will also include the Relay Settings Sheet which includes a wealth of information about the feeder coordination. This sheet describes the operating limits of the feeder breaker relays and also lists the other devices such as the largest coordinating fuses and OCRs. A sample Relay Settings Sheet is included in this section (Figure 5, 2.1.2: 16 of 16).

I. FAULT CALCULATION REQUIREMENTS

In order to determine the expected current magnitudes for faults occurring at various points on a feeder, the physical arrangement of the feeder must be known as well as the maximum available fault currents at the substation. Any current flowing in a distribution feeder is supplied from our generators through our transmission system and substation transformers. During a fault on the distribution circuit the current flowing will be a function of the combined impedances between the fault and the source (generators). In order to determine fault currents on our feeders we must obtain an equivalent impedance of our generation and transmission systems at each distribution substation. To this "system impedance" we must add the substation transformer impedance and the impedances of any current limiting reactors which may be in the circuit.

This combination of impedances is called the "Pull-Off Impedance" and is the starting point for calculating faults on the distribution circuits. Distribution feeder impedance is a function of many things such as:

1. Conductor size and type (copper or aluminum).
2. Conductor configuration - closely spaced cable, overhead conductors on crossarms or overhead conductors on triangular spacing.
3. Circuit length.

These physical characteristics are used to determine the per-unit length of impedance (ohms per mile, ohms per 1000 feet, etc.) of each of the different sizes and types of electrical conductor used on our system.

J. FAULT CALCULATION PROCEDURES

In order to simplify calculations on our three phase circuits, we normally use a method developed in 1918 by Dr. C. L. Fortescue. His solution method converts our three phase impedances down into three distinct networks called sequence networks.

1. Positive Sequence
2. Negative Sequence
3. Zero Sequence

These sequence networks are simply three single phase equivalents of the three phase system. Different types of faults will require the three networks to be connected in different ways. For example, a three phase fault on our system can be calculated by utilizing only the positive sequence networks; a single line to ground fault will utilize all three networks connected in series with each other.

Once the sequence network solution has been obtained, these results can be used to determine the actual three phase values of currents and voltages.

K. REVIEW OF THE OBJECTIVES OF COORDINATION

In order to meet the objectives for coordination, many types of equipment are connected to the distribution system. To illustrate how to achieve proper coordination, each coordination objective is reviewed below and the associated equipment is discussed. Although all these objectives should be met, sacrifices are often made using best judgment as to the resulting consequences in overall coordination

1. The scheme should allow for carrying the expected load currents without unnecessary interruptions or outages due to slight overloads.

   a. The range of current taps on the phase relays will allow their "pick-up" to be set at a value of current which will be 1-1/2 to 2 times the expected load current during normal load periods. This allows for some loading above normal without tripping the circuit.

2. The scheme should not interrupt for self-clearing faults if at all possible.

   a. We try to accomplish this with the GX relay (short-time delay ground relay). Its current "pick-up" is in the neighborhood of 1/2 the phase relays and it is effective up to about 2000 Amperes of fault current. The time delay characteristics of this relay will allow momentary faults of 1/2 cycle to occur without tripping the breaker.

3. The scheme should interrupt all non-self-clearing faults as quickly as possible.

   a. The ground instantaneous relay (GI) on the breaker is set to pick-up for faults above approximately 2000 Amperes. This insures that high magnitude faults will be interrupted as quickly as possible.

   Gi relay setting policy:

   Feeders with a CT ratio of 500:5, or a 100 X multiplier, must be set with the GI at 20, corresponding to a setting of 2000 Amps.

   Feeders with a CT ratio of 600:5, or a 120 X multiplier, must be set with the GI at 17, corresponding to a setting of 2040 Amps.

   b. The short-time-delay relay (GX) will trip the breaker quickly for faults below 2000 Amperes and above the GX minimum pick-up value. The lowest time dial required to coordinate with the OCR is used on this relay.

   c. For fault current magnitudes below the pick-up values of the station breaker, line reclosers with their fast trip characteristics are used in order to meet our Reach Factor guideline.

4. The scheme should re-energize the circuit to test for temporary or permanent faults. (Temporary faults should not cause permanent outages.)

   a. The reclosing relay automatically recloses the breaker with a 0.4 second time delay after it trips from either the GX or GI. This action tests the circuit. If, when the breaker recloses, there is no fault current flowing, then no further tripping takes place and the reclosing relay resets itself in 10 seconds.

   b. If, when the breaker recloses, there is fault current flowing then the phase (AT, BT, CT) or ground (GT) time delay relays start timing.

5. The scheme should allow for clearing of permanent faults by those interrupting devices nearest the fault.

   a. When the long time delay relays start timing following a breaker reclosing, this indicates that the fault that initiated tripping is permanent in nature. By selecting time dial settings on the station breaker relays, the long time delay relays can be coordinated with ("set above") other devices farther out on the feeder. Those devices are usually fuses or line reclosers. This coordination allows these other devices to clear the fault from the circuit before the station relays have an opportunity to trip the breaker again. If the coordination is correct, the device nearest the fault will trip; either a fuse will "blow" or a line recloser will lock out.

6. The scheme should allow permanent outages on the smallest possible amount of circuit.

   a. When a fuse blows during a permanent fault only the portion of circuit beyond the fuse will experience an outage, usually a single or two-phase lateral.

   b. When a line recloser locks-out only the circuit beyond it will experience an outage. This could be a portion of the three-phase feeder or a portion of a single or two-phase lateral.

L. UNDERGROUND CONSIDERATIONS

Different settings are required for either conventional underground feeders, completely URD feeders or conventional underground feeders with an overhead source.

1. Conventional Underground (UG Automatic Throwover System in Duct & Manhole)

Faults on conventional underground feeders are usually permanent. They should be cleared promptly, but with enough time delay to allow any sectionalizing or transformer fuse involved to blow. The confined space of vaults and manholes make it undesirable to reclose into a permanent fault. The OCB on the conventional UG feeder should be set for one time delayed operation with no reclosure and no Gi/Gx.

2. Underground Residential Distribution.

FPL has experienced temporary faults on URD systems. To prevent unnecessary outages, it is desirable to use the normal sequence of breaker operations for overhead feeders on a URD feeder. Where URD risers are fed from an overhead feeder, the normal sequence of breaker operations for overhead feeders should be used. If the URD fault is permanent, the riser fuse should blow during the time delay period and the feeder will be restored.

3. Conventional Underground – Overhead Source.

In the case of a section of conventional underground that is fed from an overhead feeder, the normal sequence of breaker operations for overhead feeders should be used. This will allow a riser fuse to blow and clear the fault. A recloser (OCR) can also be used to obtain the desired one-time-delayed operation with no reclosure to the underground circuit. Depending on the relative size of overhead and underground loads, the recloser might be used to feed the riser, or the overhead feeder section.

M. POLICY AND PRACTICES

1. Reach Factor Protection Policy

The Reach Factor is the ratio of the maximum available fault current at the end of the circuit (For example: end of feeder, recloser, or lateral line) to the minimum tripping value of the device (breaker, fuse or recloser) protecting the line, considering a 3 phase, phase to phase, or a phase to ground fault.

Reach factor = Maximum available fault current at the end of the circuit / Protective device minimum tripping value

Our Reach Factor Protection Policy requires a minimum Reach factor of 1.5 for all 3 types of faults (3 Phase, Phase to Phase, or Phase to Ground faults)
The Reach Factor policy of 1.5 is necessary to allow a safety margin, considering that not all short circuits involve “bolted faults”. (a zero impedance fault)

Sample calculations: Let's assume a certain feeder has the following maximum available fault current values at the end of the line: 3 phase fault current = 1000 Amps; Phase to Phase fault current = 866 Amps (Note: Phase to Phase Fault = 86.6% of the 3 Phase Fault Current); Phase to ground fault current = 550 Amps.
The feeder is protected by a feeder breaker with the Phase time delay relays set at a minimum of 600 Amps, and the Ground long time delay relay is set at 300 Amps.
The Reach Factor calculation is performed as follows:

3 Phase fault Reach factor = 1000 / 600 = 1.67 (Meets the Reach Factor Protection requirement)
Phase to Phase fault Reach factor = 866 / 600 = 1.44 (Does not meet the Reach Factor Protection requirement)
Phase to Ground fault Reach factor = 550 / 300 = 1.83 (Meets the Reach Factor Protection requirement)

Since our policy requires a Reach factor greater than 1.5 for each and all of the 3 types of faults, the Reach factor Protection Policy is not met for this example. This type of protection issue usually occurs on long rural feeders, where the available fault currents are low at the end of the line because of the distance. The most common solution is to install a recloser to protect the end of the line. The load currents towards the end of a rural feeder are usually low, therefore, let's assume in this example that the load demand is only 75 Amps. We should try to load reclosers at no more than 80% of its name plate rating, therefore, lets install a 100 Amp recloser. Our mechanical reclosers trip at 200% of rating, in this case, 200 Amps. Let's make the reach factor calculations again:

3 Phase fault Reach factor = 1000 / 200 = 5.0 (Meets the Reach Factor Protection requirement)
Phase to Phase fault Reach factor = 866 / 200 = 4.33 (Meets the Reach Factor Protection requirement)
Phase to Ground fault Reach factor = 550 / 200 = 2.75 (Meets the Reach Factor Protection requirement)

The recloser allows us to meet the Reach factor policy for all fault conditions.

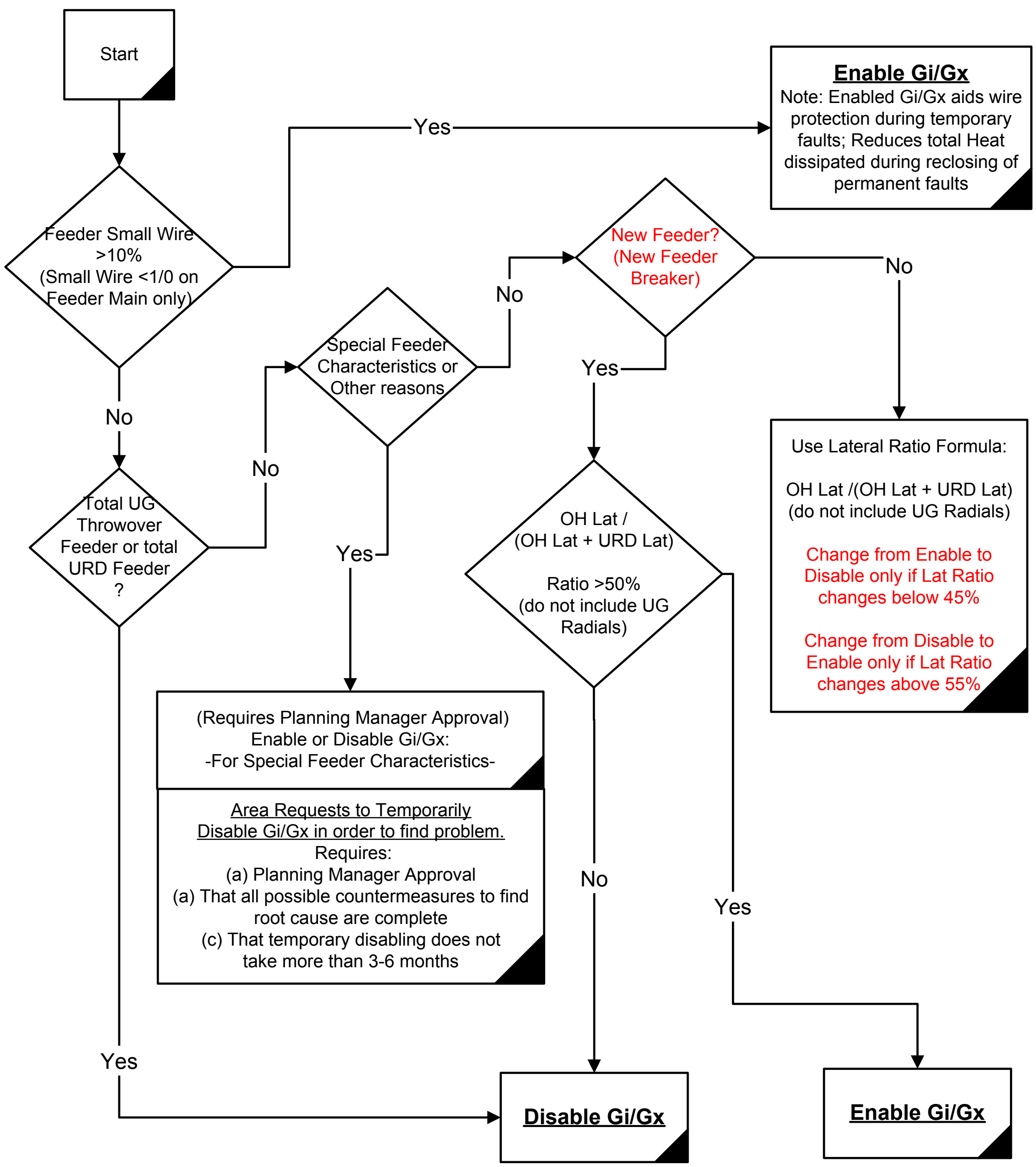
2. Gi/Gx Implementation Policy

The Gi/Gx Feeder Selection Criteria considers two protection schemes:

a) Fuse-saving scheme: Enabling the GI/GX is a fuse-saving scheme. That is, the breaker clears temporary faults on laterals and fewer fuses blow on the typical feeder with this scheme. In particular, this scheme is very advantageous because it provides better protection for our OH feeders as it quickly clears temporary faults due to lightning and other causes on the feeder line, thus avoiding equipment damage, permanent interruptions to all customers on the feeder, and reducing costs due to restoration and repairs. The possible increase in momentaries is the obvious disadvantage. All customers on a feeder with this scheme will experience a blink for most lateral faults.

b) Breaker-saving scheme: When the GI/GX is not used, the scheme is said to be, "breaker-saving". The disadvantage to this scheme is that small wire on the feeder backbone is more susceptible to damage as faults stay on the system longer. There may also be some commercial customer that can not tolerate possible voltage sags.

Gi/Gx Feeder Selection Criteria



The following figures show some examples of items used in protection/coordination analaysis.

Figure 1: Relay Curves

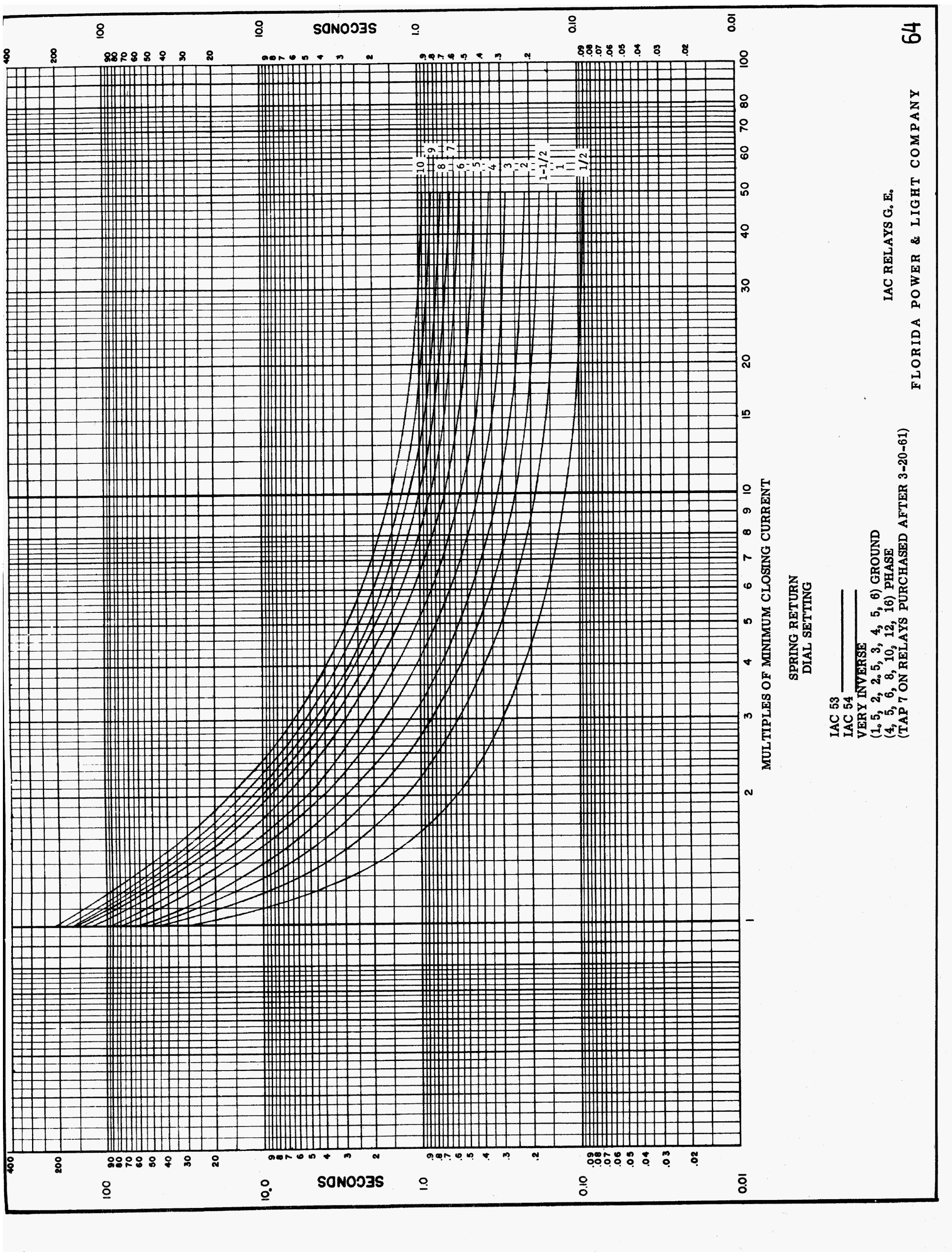


Figure 2: Fuse Curves

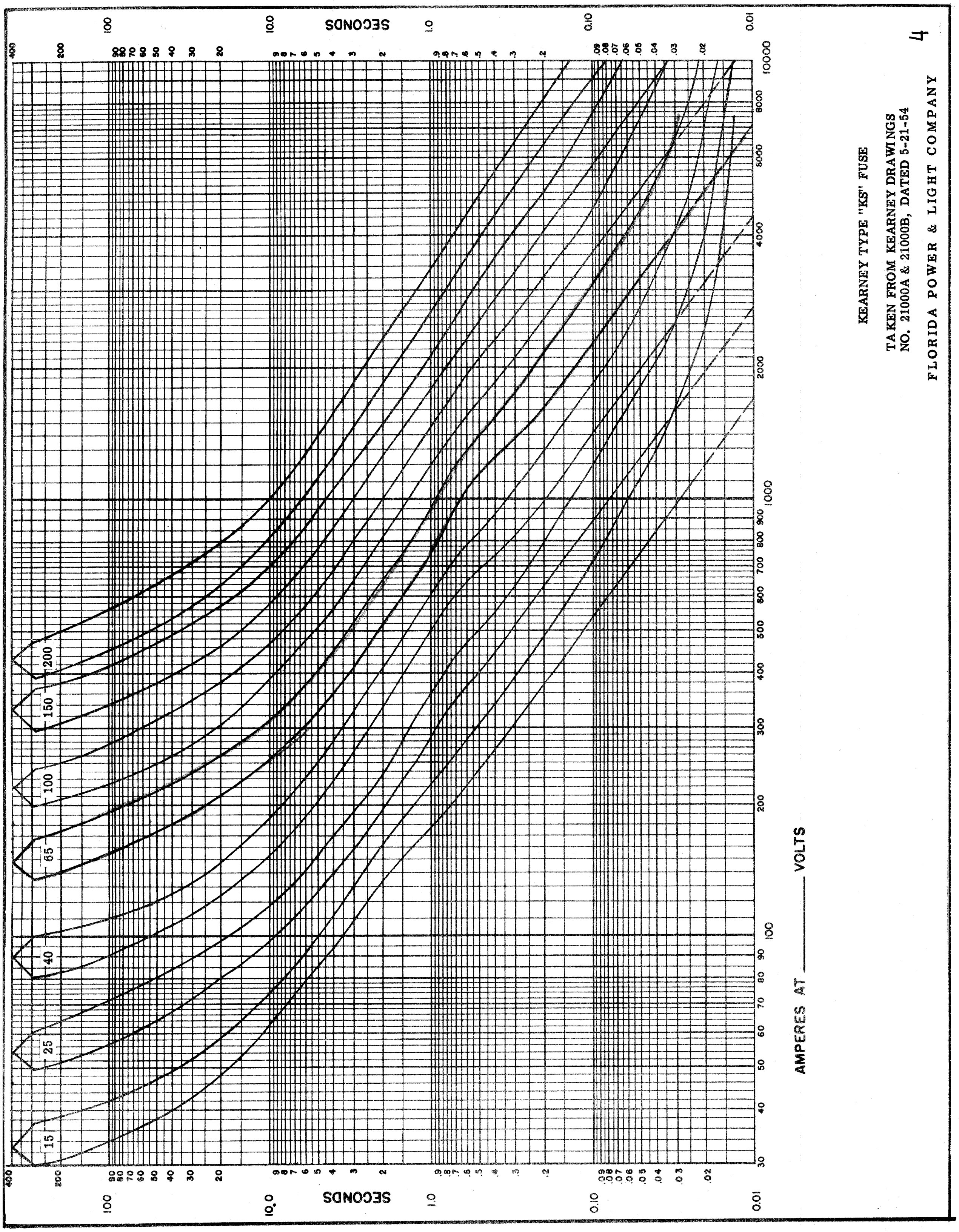


Figure 3: Line Recloser Curves

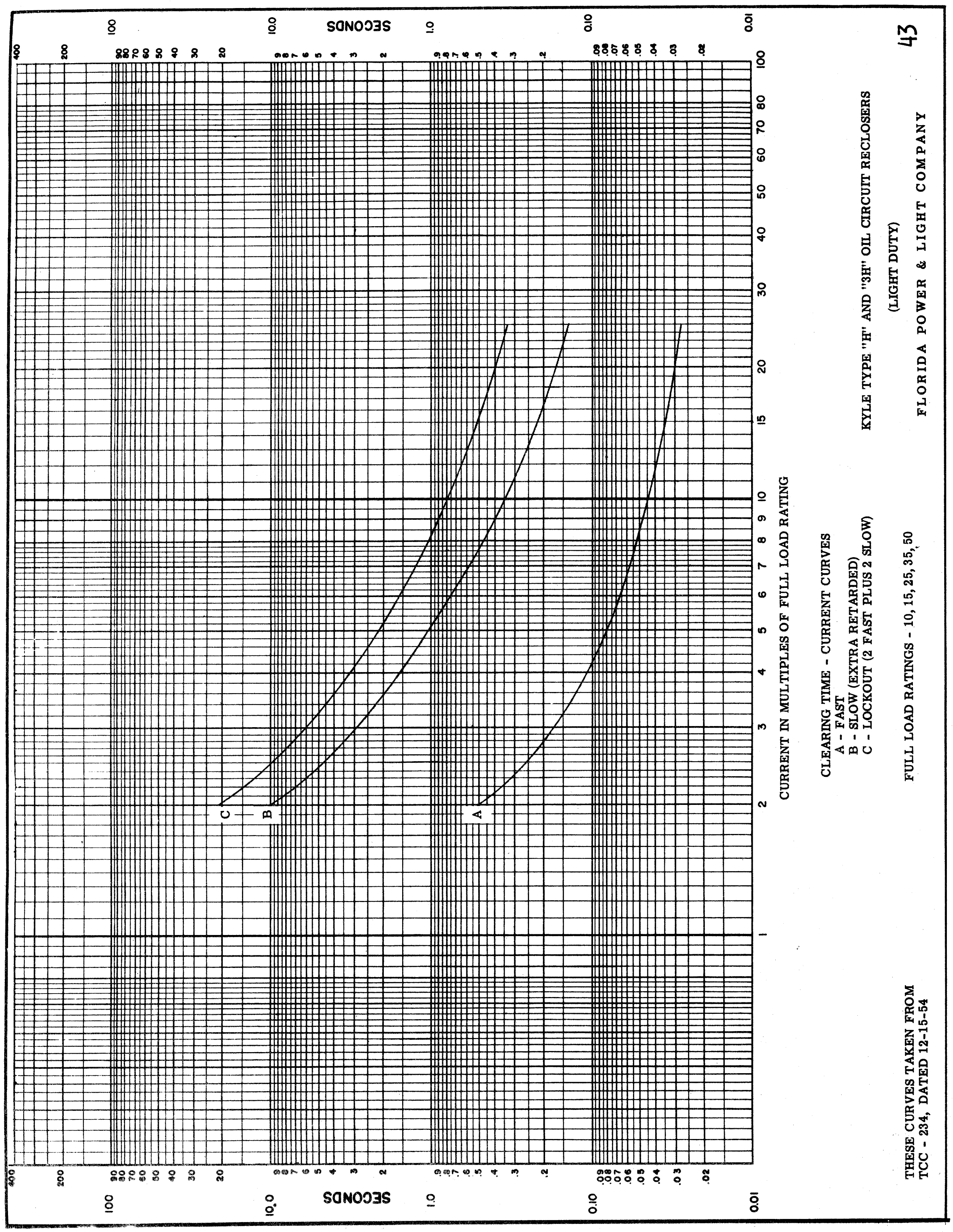


Figure 4: Feeder Coordination

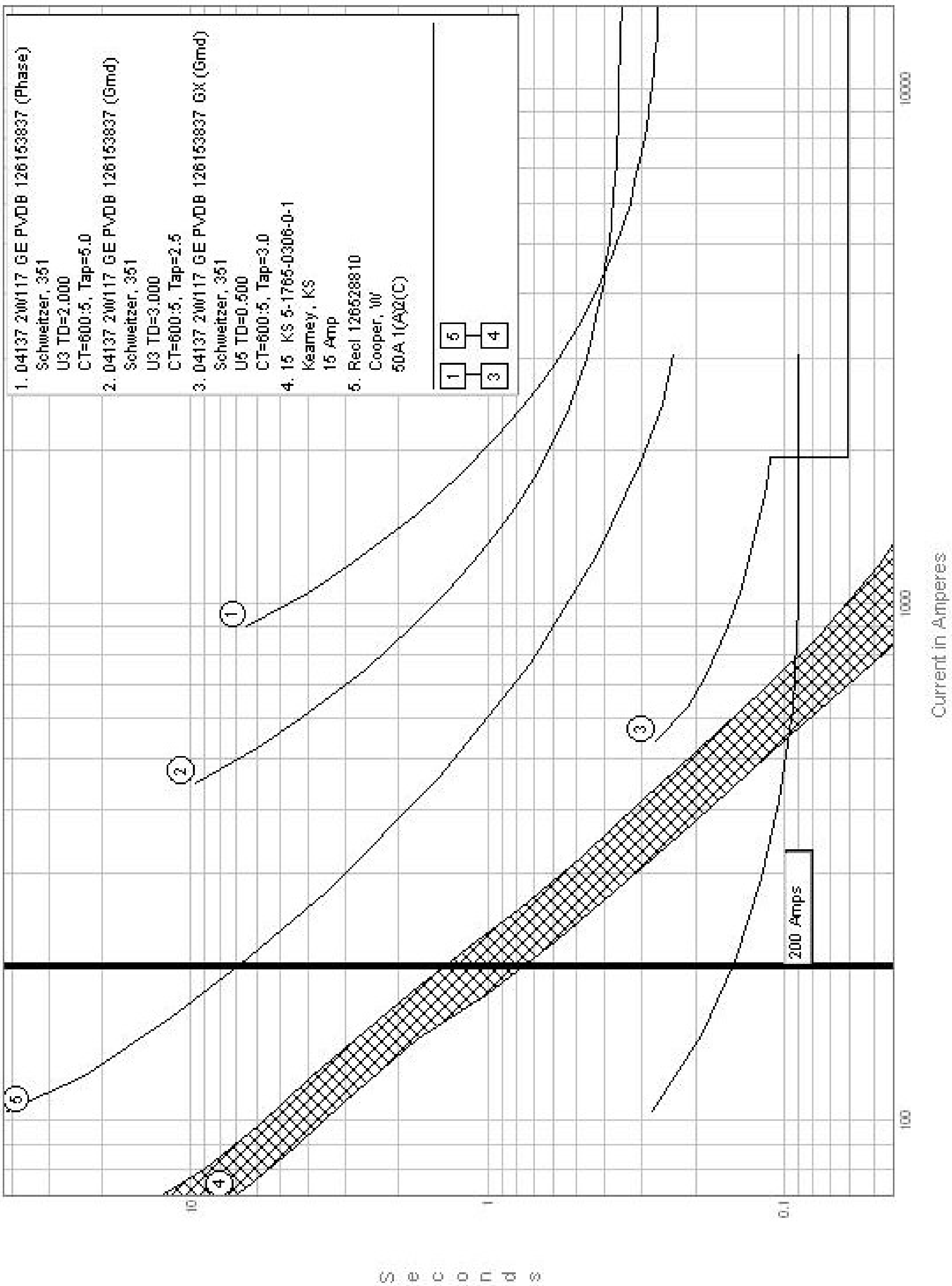


Figure 5: Relay Settings Sheet 1. (The relay setting sheet (Figure 5) depict one feeder with the GI/GX ground relays enabled and another with the GI/GX ground relays disabled. There is a tradeoff with the use of the GI/GX)

Authorization Date | **FLORIDA POWER & LIGHT COMPANY** | **Page 1 of 1**

Interoffice Correspondence

To:
Settings Manager, Concept Development
TLD/JB

Copies To:
Station Area Manager — **3** TRS
Power Quality Supervisor — **4** File Copy

From:
Distribution Reliability Planning
Todd Bolkema DPR/SS2

Substation:
RUBONIA 23KV

* Indicates a change by this revision

	Item/Feeder	505261	505262	505263	505264	INSP
	OCB Switch Number	3W85	3W97	3W29	3W40	3W73
	OCB Number 37-	22270	19469	419961	462770-0	392501-7
	Manufacture	MGE	MGE	SQD	GE	MGE
	Type	VAC	VAC	VAC	PVBD	VAC
	Size	1200	1200	1200	1200	1200
	OCB Clearing Time	3.0	3.0	3.0	3.0	3.0
	CT Ratio	600 :5	600 :5	600 :5	600 :5	600 :5
	Date Last Authorized	06/19/03	05/01/01	06/19/03	06/19/03	06/19/03
	SEL351 Template				A02D	
Phase Relay	Type-Curve	IAC-53	IAC-53	CO-9	351-U3	IAC-53
	Current Tap	5.0	4.0	5.0	4.0	5.0
	Time Dial	2.0	2.0	2.0	2.0	2.0
	Primary Amps	600	480	600	480	600
Long Time Ground Relay	Type-Curve	IAC-53	IAC-53	CO-9	351-U3	IAC-53
	Current Tap	2.5	2.0	2.5	2.0	2.5
	Time Dial	4.0	5.0	4.0	4.0	4.0
Short Time Ground Relay	Type-Curve	CO-2	CO-2	CO-2	351-U5	CO-2
	Current Tap	3.0	2.5	3.0	2.5	3.0
	Time Dial	0.5	0.5	1.0	0.5	1.0
	Inst Setting	14	14	16	14	10
	GX Status	Disabled	Disabled	Enabled	Disabled	Enabled
	GI Status	Disabled	Disabled	Enabled	Disabled	Enabled
	RC Toggle	GIGX	GIGX	None	GIGX	None
Reclosing Relay	Type	SLR	SLR	ITE79M	SEL351	ACR
	Seq. 1 (sec)	0.4	0.4	0.4	0.4	0.5
	Seq. 2 (sec)	15.0	15.0	15.0	15.0	15.0
	Seq. 3 (sec)	30.0	30.0	30.0	30.0	30.0
	Seq. 4 (sec)					
	Reset (sec)	10	10	10	10	10
Winter Group 6	Ph Current Tap				5.0	
	Ph Time Dial				2.0	
Winter Emerg Group 5	Ph Current Tap				6.0	
	Ph Time Dial				2.0	
	Largest Coord Fuse	65KS	65KS13	65KS	65KS	65KS
	Smallest Coord Fuse	50KS		50KS	50KS	65KS13
	Conductor/Other Fuse			80KS13	80KS13	
	Largest Coord OCR	70WV	140RX	100RX		140RX
	Smallest OCR	70RV	140RX			140RX

Reason For Issue:

Date Last Issued:

Prepared By : Dept: DPR/SS2

Normal & Group 6 Reviewed By : TLD / JB
By: ____________________
Date: ____________________

Relays Set As Specified
By: ____________________
Date: ____________________

Form DPR1 Rev. 02/11/02

2.1.3 CAPACITORS – THEORY AND APPLICATION

Almost all of FPL customers have appliances which include motors and other inductive devices. This makes the customer's load current lag the line voltage. The distribution system has to supply lagging KVAR's to the Customer, as well as KW's. The current associated with the lagging KVAR's increases the line current and consequently, the losses and voltage drop are increased. Capacitors installed near the load can supply these KVAR's. This will reduce the line current to that amount needed to supply the load KW. This will eliminate the line losses and voltage drop which would have been associated with the extra current needed to supply the lagging KVAR's.

Another way of stating this situation is that motors take lagging current. Capacitors take leading current. By connecting enough capacitors to the line near the motors, the lagging current will be canceled and the line current reduced.

FPL uses shunt primary capacitors to accomplish this.

A. PRIMARY SHUNT CAPACITORS

1. Philosophy

To obtain the maximum benefits from the use of capacitors, attention should be given to the VAR Management Goals and the application of capacitor banks. The application of capacitor banks is influenced by the daily and seasonal load variations as well as by economic considerations.

a. VAR Management Goals

The Distribution Feeder VAR Management Goals were established in 1982. The goals are stated below:

Summer - Maintain between 0.98 lag and unity power factor at peak load periods.

Valley - Maintain less than 0.98 lag power factor from 1:00 a.m. to 5:00 a.m., from November to April.

This is intended to coordinate the distribution feeder VAR supply with the power system needs. This policy does not apply on winter peak load days.

Winter - Use remote, load or voltage controlled banks for peak load VAR control as appropriate for feeder conditions.

This goal is meant to help with voltage and system loading problems associated with the extremes of winter loading. Remote control is the preferred method, with load control preferable over voltage control for this purpose.

b. Goals Chart

The chart below is an expansion of the goals and should help clarify the intent of the goals.

a) Period		Substation Desirable Power Factor Range
Spring and Fall valley loading	Natural	0.98 lag
Summer peak loading	0.98 lag to	Unity
Valley load during summer	0.95 lag to	0.99 lead
Winter peak loading	0.98 lag to	0.98 lead
AM valley during winter peak	0.95 lag to	Unity
PM valley during winter peak	0.98 lag to	0.98 lead

The power factors given are for substation total loading after taking into account VARs supplied by the substation capacitor banks which are not considered part of the distribution VAR supply. Substation capacitor banks are under the control of the System Dispatcher and are not to be counted for credit toward meeting the distribution VAR supply goals.

1) Load Variations

Daily and seasonal load variations have a large impact on the application of capacitor banks. The need for capacitors on the distribution feeder is proportional to the load on the feeder. As the load varies daily and seasonally the need for capacitors is constantly changing. These constantly changing factors, along with the fact that capacitors are discrete and not continuously variable, make maintaining a proper power factor difficult.

2) Economic Considerations

Four variables influence the economics of capacitor application. These variables are:

i. Cost of capacitors

ii. Cost of losses in the power system

iii. Location of the VAR loads

iv. Daily and seasonal load cycle.

These variables interact so that the sizing and placement of distribution capacitor banks becomes a challenge of choosing an optimal balance between the variables that results in the highest benefit to cost ratio. In general this means setting the largest possible bank as close to the load as possible.

2. Operating Conditions

a. Types of Controls

Capacitor banks in FPL are majority controlled by the Remote Controlled Capacitor System (RCCS). This system switches the cap banks on and off using radio or paging signals. The cap banks are equipped with vacuum or oil switches that will energize or de-energize the capacitor bank.

The next group of banks is fixed banks. Fixed banks do not have switches and require a field visit to operate. The goal is to situate fixed banks where they can stay energized all year and do not have be taken out except for maintenance or repair.

There are a few banks in rural areas that are not under the control of RCCS because of lack of radio signals. This banks are switched by a time clock preset to turn the bank on and off in line with a typical daily load cycle.

There are also a few remaining switched banks that are controlled by voltage or power factor. These are for specific locations where large customers may be located or where voltage problems may be prevalent.

Capacitor banks that can be installed for underground situations have been introduced to the FPL system starting in 1999. These are capacitor banks that are installed in deadfront padmounted switch cabinets. At the present, they are located primarily on URD feeder sections. The banks have switches for future remote control capability, but are presently operated as fixed banks. As the cost of the URD banks are considerably higher than the traditional overhead bank, an economic assessment needs to be completed before installation.

b. Switching Requirements

Because of the natural power factor on our system, fixed banks are used as a ‘base’ load to bring the power factor up to a minimum level that will be required all year long. Switched banks are then used to increase or decrease the vars needed as the power factor varies during its daily load cycle and its yearly cycle. It is a goal to eventually have all fixed banks in a proper location to accomplish this without manual field switching.

In areas where transformer scada telemetry is available, the vars can be monitored to measure the power factor of the transformer throughout the day. With the use of RCCS, and a preset power factor level determined by Power Supply, capacitor banks can be automatically and remotely switched on and off based on the amount of vars needed to correct the power factor to the desired level.

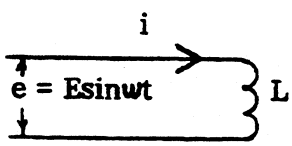
In areas where transformer telemetry is not available, a preset schedule is programmed into the master controller of the RCCS. This schedule is based on knowledge of the daily load cycles, as well as the seasonal cycles, and can take into consideration weekends and holidays.

In both of these cases, there is a manual override which enables the Power Quality group to control the operation of the banks for var flow during contingency conditions.

In the rural areas where RCCS is not operable, the cap banks are normally switched with the use of time clocks. These clocks are manually set in the field to switch the banks in and out based on a daily load cycle. They are not flexible during seasonal changes, and must be reset when var conditions change.

3. Purpose Of Shunt Capacitors

Consider a composite load that includes motors or other inductive devices. To establish a phase relationship between current and voltage in an inductive circuit, refer to the simple circuit below.

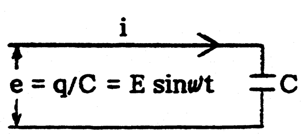


Where:
E Sinwt is the applied voltage;
i is the circuit current
L is the circuit inductance

Here, e = L di/dt = E sinwt. Therefore, integrating both sides, and dividing by L, we get: i = E/(W L) Coswt. The sine curve starts at zero at t equals zero: the - cosine curve starts at - 1 at t equals zero and does not reach zero until 90 degrees later. Thus the current in an inductive circuit lags the voltage by 90 degrees. If there is also resistance in the circuit, the angle of lag will be less than 90 degrees.

We will call this angle φ. The total current i will lag the voltage by the angle 0-; it will have a component I cos φ, in phase with the voltage, and a component, I sin φ, lagging the voltage by 90 degrees. The "in phase" component produces power; the lagging component does nothing but increase the circuit losses and voltage drop. Cos φ is expressed as a decimal or in percent, and is the "power factor."

It is not possible to eliminate the lagging component in the load itself. However, it is possible to eliminate or minimize it in the distribution system supplying the load. This can be done by installing capacitors on the system near the load. Consider the phase relationship between the applied voltage and the capacitor current in the simple circuit below.

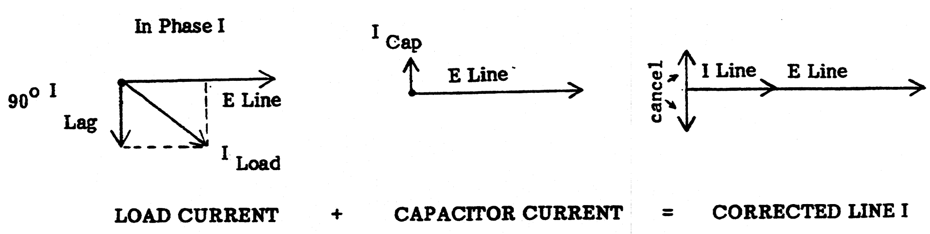


Where:
E Sinwt is the applied voltage.
i is the circuit current
C is the capacitance in farads
q = charge on capacitor

e = q/C; thus E sin t = q/C

Take the derivative of both sides; we get: E cos t - (1/C) dq/dt. But dq/dt is the current; so i - C E cos t. The positive cosine curve reaches its positive maximum 90 degrees before the sine wave reaches it's positive maximum. The current in a capacitive circuit therefore leads the applied voltage by 90 degrees. Normally, the resistance in a capacitive circuit is very low; the angle of lead is not exactly 90 degrees, but very close to it.

With the right amount of capacitance installed near the inductive load, the current flowing from the generator through the line to the capacitor location will consist of: (a) a component which is a sine wave in phase with the line voltage; (b) an inductive component which is a negative cosine wave lagging the line voltage by 90 degrees and (c) the capacitive current which is a positive cosine wave leading the line voltage by 90 degrees. It is of the same magnitude as the inductive component. Obviously the positive and negative cosine waves will cancel, leaving only the in-phase component. We have thus minimized the current, and consequently the voltage drop, and the line losses. The circuit is said to have unity or 100% power factor. This same concept may be shown, by a vector diagram, as follows:



Another concept which is useful in applying capacitors is that of reactive supply. A load taking a lagging current requires both real and reactive power from the system. These are referred to as KW and KVAR, respectively. The formula, on a single phase basis is:

$KVA_{Load} = E_L (I_L \cos \varphi_L + jI_L \sin \varphi) = E_L I_L \cos \varphi + jE_L I_L \sin \varphi = KW + KVAR.$

A capacitor requires essentially only leading reactive power from the system, since its losses are very low. Thus,

$KVA_{cap} = E_L (I_C \cos \varphi_C - j\, I_C \sin \varphi_C)$, where φ_C□90°. Therefore,

KVA_{cap}□$O - j\, E_L I_C \quad - j\, E_L I_C \quad - KVAR.$

The load reactive power carries a positive sign; the system must supply KVAR to it. The capacitor reactive power carries a negative sign; it supplies KVAR to the system. Thus the capacitor can be thought of as a generator of reactive power. Then the load reactive does not have to flow all the way out from the source. This results in minimum line current and helps to minimize losses and voltage drop.

The voltage drop is reduced for two reason; namely:

1. Minimum current through the line impedance results in a smaller voltage drop.
2. The current is in phase with the voltage. This minimizes the effect of the voltage drop through the inductive component of the line impedance.

We therefore see that capacitors are applied on distribution systems:

3. to reduce losses,
4. to improve voltage conditions, and
5. to supply reactive which would otherwise have to come from the generator.

They are applied so as to minimize line current and voltage drop. In some cases, they may be applied to cause a voltage rise in a part of the circuit. Additional examples, with vector diagrams and discussion will be given to emphasize some of the results of applying capacitors.

Figure 1 shows an inductive load fed from a generator through a line having an impedance equal to R + jX. Assume a capacitor sized to match the lagging KVAR of the load has been added. The capacitor acts as a KVAR generator, supplying the exact amount of reactive power (KVAR's) required by the load. The combination of lagging power factor load and capacitor presents a unity power factor load to the line. The line is required to furnish only real power (KW) to the load. The line and Generator current is:

I = KW/E_R, where KW = Load Kilowatts, and E_R = Receiving end voltage in kilovolts.

A vector diagram showing the voltage drops and voltage current relationships is shown in Figure 2. Note that the power factor Angle "0-" (Angle between "I" and "E_R") is zero. Power Factor = COS0- = 1. Now assume that the switch in Figure 1 is opened taking the capacitor out of service. The line must supply the real and reactive power requirements to the load, plus the KW and KVAR line losses. In this case the line and generator current is:

$$I = \frac{KVA}{E_n}$$

WHERE: KVA = The Load Kilovolt-Amperes

Figure 3 shows the new vector diagram for the circuit without the capacitor bank. We shall assume that the sending end voltage "E_S" is increased enough to maintain "E_R" at its former value. The line and generator current has increased by the factor 1/COS0- = KVA/KW. The line voltage drop has also increased. The line voltage drop is E_S - E_R which can be approximated by the formula: E_S-E_R IRCOS0- + IXSIN0-. This formula is sufficiently accurate for most calculations where the Angle "B" is small, as is the case for most distribution circuits, and where IZ is not more than 15 to 20% of E_S.

a. Reduce Reactive Power Generation

By installing capacitors near the loads on distribution feeders, the reactive power requirements of the loads can be supplied locally. This reduces the reactive power that would otherwise have to be supplied by the generators and transmitted from the plant to the loads. This results in increased capacity to serve load all along the system, from the plant to the load. I^2R losses along the line are also reduced because of the lower value of current.

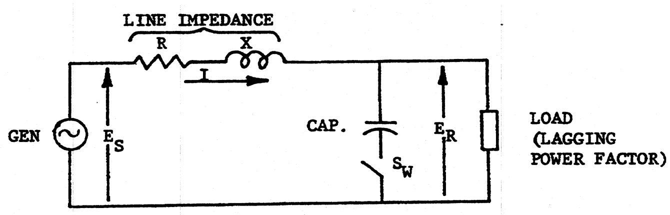


FIGURE 1. SINGLE PHASE CIRCUIT DIAGRAM

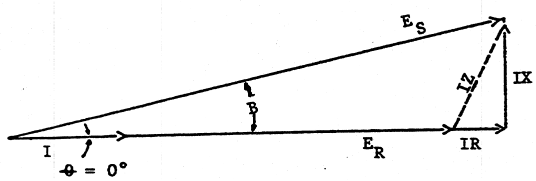


FIGURE 2. VECTOR DIAGRAM FOR CIRCUIT OF FIGURE 1 WITH SWITCH CLOSED. CAPACITOR BANK KVAR = LOAD KVAR (UNITY POWER FACTOR LOAD)

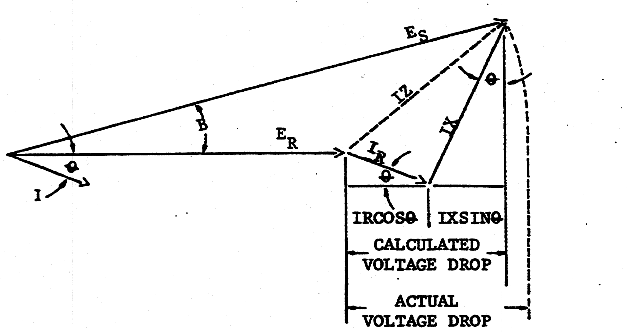


FIGURE 3. VECTOR DIAGRAM FOR CIRCUIT OF FIGURE 1 WITH SWITCH OPEN. (LAGGING POWER FACTOR LOAD)

$E_S - E_R \approx IRCOS\theta + IXSIN\theta$

b. Improve Low Voltage Conditions

We have seen that supplying the Reactive Power near the load will reduce the current from the capacitor back to the generator. This reduces the IR drop and the IX drop. However, the decrease in the Power Factor Angle "φ", is the most significant factor affecting voltage drop along the line. This factor is quite significant since the line reactance is normally several times larger than the line resistance for open wire lines. Because of this, it is possible to substantially reduce the voltage drop between the sending and receiving end of an open wire line by adding capacitors. Figure 4, 5 and 6 show the vector diagrams for a circuit with unity power factor, lagging power factor and leading power factor loads. These diagrams demonstrate the significance of the power factor Angle "φ" on line voltage drop. Note that the receiving end voltage "E_R" can be greater than the sending end voltage "E_S" when the circuit has a leading power factor, and line reactance is greater than the line resistance.

Most distribution feeders will have the load distributed along the length of the feeder rather than at the end of the line. It is common practice to install several capacitor banks along the feeder to account for this spatial distribution of load. A one line diagram of such a feeder is shown in Figure 7. For simplicity the load is shown concentrated at six different locations along the line. The voltage profile for this feeder with and without the capacitors is shown in Figure 8 to demonstrate the actual voltage rise that would be obtained on such a feeder. The power factor of this feeder is approximately unity with the capacitors indicated.

4. Applications Of Capacitors

The application of capacitors on distribution circuits can be divided into two categories; Feeder Power Factor Correction and voltage control. Although these two effects are very closely related, the distinction will be made to point out the different considerations involved. Feeder Power Factor Correction as used here, refers to the bulk application of capacitors on feeders to correct the power factor on the feeders and the system as a whole. Voltage control will refer to the application of capacitors for the sole purpose of raising the voltage at a particular location. Capacitors used for this purpose will also change the feeder power factor.

a. Feeder Power Factor Correction

To correct the power factor on a feeder, we must know the KVAR load on the feeder and how this load varies. Knowing this, we can decide on the amount of fixed and switched KVARs to install and the type of controls and control settings to use on the switched banks.

The majority of distribution feeders are residential or serve small businesses with load characteristics similar to residential loads. The residential feeder has load fluctuations that are primarily functions of time of day and time of year. During the summer months the load minimum occurs about 4:00 A.M. with a power factor near 85%. The load gradually increases throughout the morning and early afternoon, reaching a peak at about 5:00 P.M. The power factor during the peak is around 90%. The load gradually declines during the evening and early morning hours, reaching the minimum again around 4:00 A.M. The KW load level minimum is usually about 45% of the KW peak load level. The daily fluctuations in the winter follow the same general pattern, but at reduced load levels. A graph of the load profile for a typical feeder is shown in Figure 9.

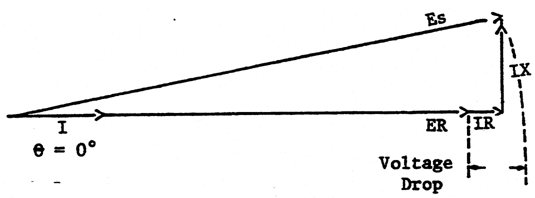


FIGURE 4.
UNITY POWER FACTOR LOAD

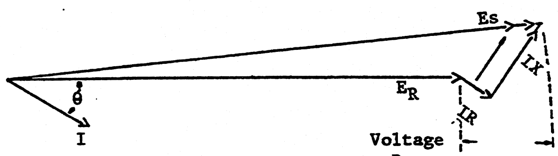


FIGURE 5.
LAGGING POWER FACTOR LOAD

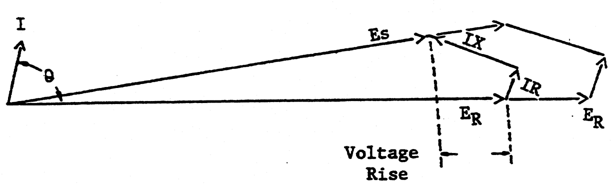


FIGURE 6.
LEADING POWER FACTOR LOAD

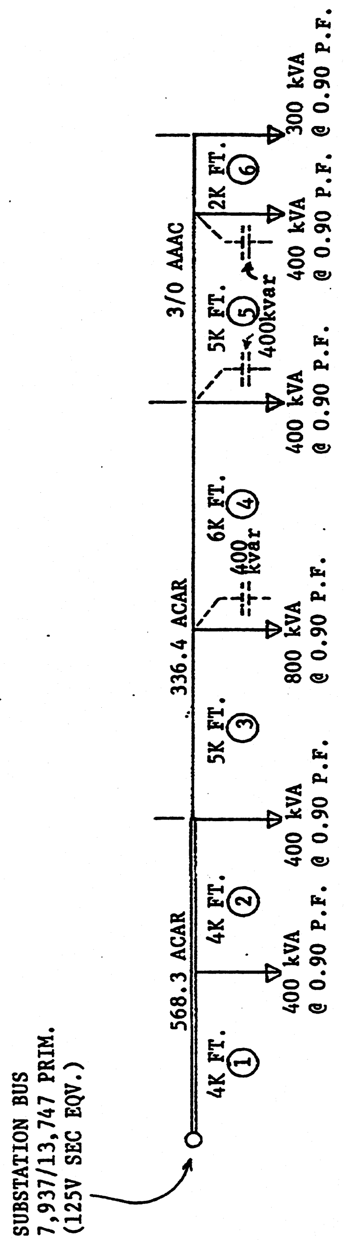


FIGURE 7. ONE LINE DIAGRAM OF TYPICAL FEEDER SHOWING LOAD DISTRIBUTION AND CAPACITOR BANKS.

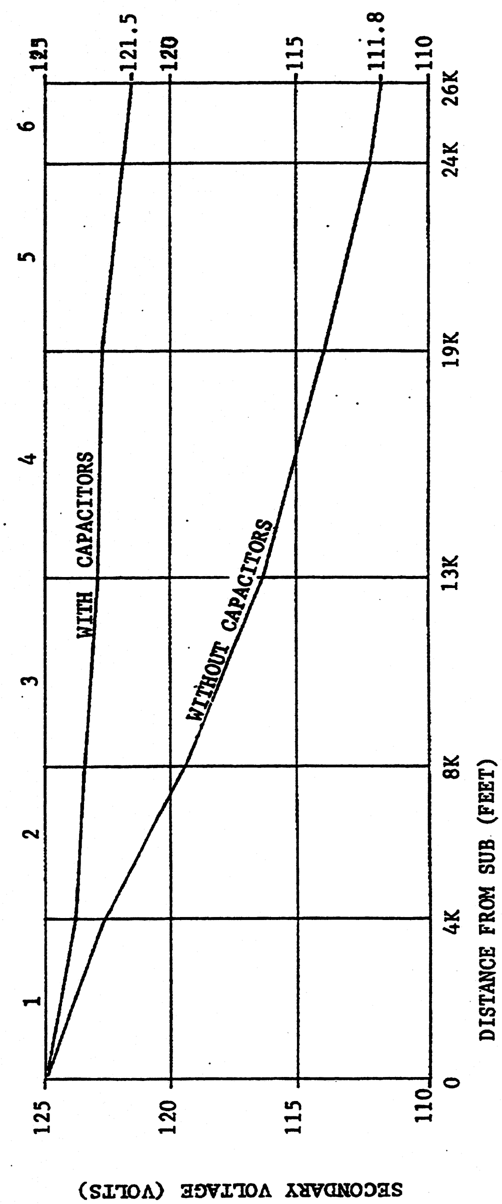


FIGURE 8. VOLTAGE PROFILE FOR FEEDER OF FIGURE 7 WITH AND WITHOUT CAPACITORS.

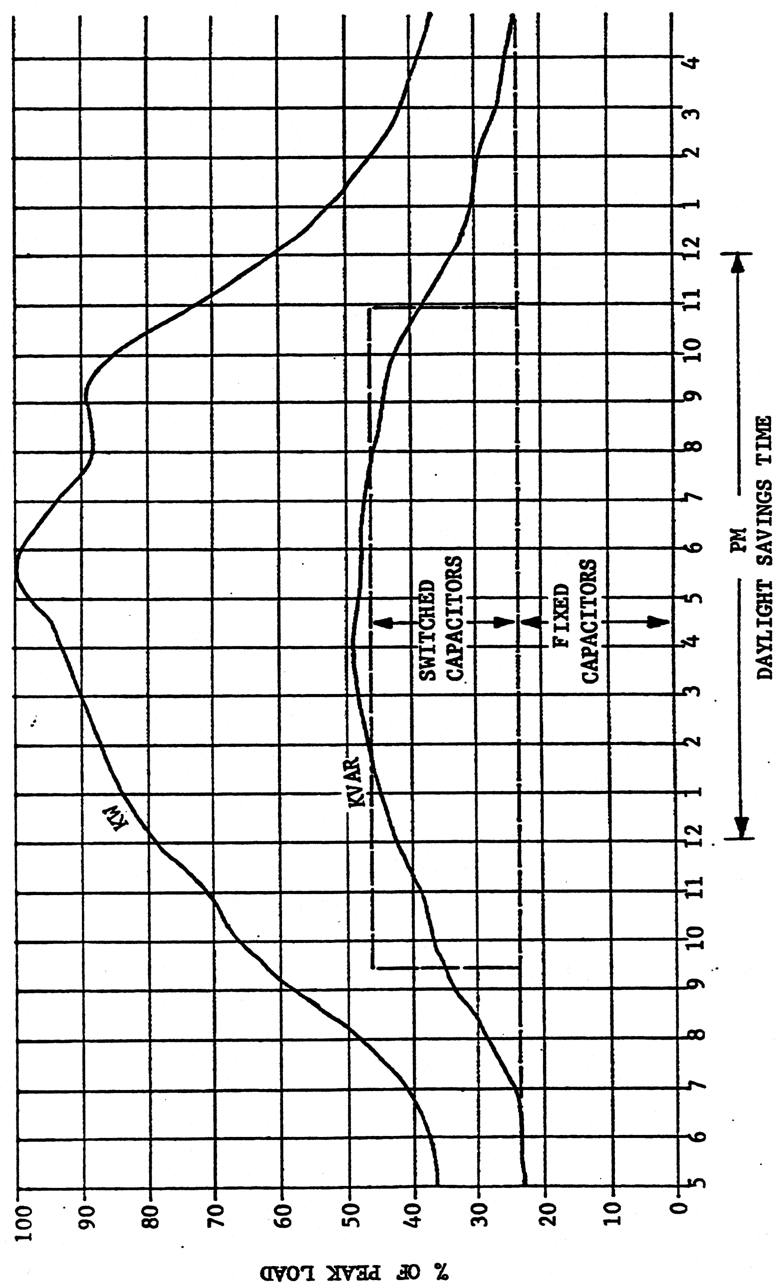


FIGURE 9. LOAD PROFILE FOR TYPICAL RESIDENTIAL FEEDER DURING WARM SUMMER MONTHS.

Feeders serving large industrial or other non-residential areas, may have unusually low power factors or widely fluctuating KVAR demands. The power factor on these feeders should be evaluated on an individual basis, as a different schedule may be required to adjust for the specific demands.

A yearly KW/KVAR survey is done by the Reliability Planning Group. Information is obtained from the RCCS Telemetry Data, Primary Maps, Line Section Data and Planning Load Maps. Computer programs are used to determine the KVAR load distribution along the feeder, including the expected power factor at the substation. The typical residential feeder will have a nearly constant load power factor along the length of the feeder.

This information is then used to decide what size and type banks to install and where to locate them. Maximum benefits are obtained by correcting the power factor during the peak load periods. This is when system and feeder loads are near full capacity. The amount of capacitive KVARs to install and the ratio of fixed to switched banks is based on the load profile during peak time of year, which normally occurs during the warmest summer months.

It is Company design practice to limit the voltage rise due to a capacitor bank to 2-1/2% for switched banks and 5% for fixed banks. This was done to keep voltage changes during switching low enough to avoid customer complaint. Capacitor banks should be located near or just beyond the major loads or load centers along the feeder. Where possible, they should be sized to match the load in major switchable line sections. Then capacitor banks will not need to be relocated should feeder switching boundaries be changed.

The presence of our 500 kV transmission circuits and their relative high capacitive contribution to the transmission system, voltage control during light and valley loading has become very important. Proper control of distribution capacitors can assist in minimizing the amount of inductive reactance required to "bleed off" capacitive VARs from our 500 kv lines during light loads

b. Voltage Improvement

Occasionally a low voltage condition may exist, even though the Feeder Power Factor has been corrected and the substation regulator is properly adjusted. This most often occurs at the feeder extremities such as the end of a long lateral or near the end of a long feeder. Usually, only a small percentage of the total feeder load is located here. In these instances it may be possible to correct the low voltage condition by installing capacitors. This may defer or eliminate the need for more expensive alternatives such as installing line regulators, reconductoring or voltage conversion. Low voltage conditions such as this will warrant making some voltage and current measurements in the field. Also, make a more detailed analysis of the feeder than is required for General Power Factor Correction. It is helpful to refer to a model of the feeder showing conductor sizes, line section lengths, line section loads and existing capacitor banks. Use available computer programs to determine optimum capacitor banks sizes and locations. It may be necessary to over-correct a small section of line and operate with a leading power factor to obtain the desired voltage rise. Leading power factors smaller than 85% should be avoided. Again the voltage rise for a capacitor bank should be limited to 2-1/2% for switched banks and 5% for fixed banks to avoid objectionable sudden voltage changes.

Adding capacitors to only one or two phases can cause unbalanced phase currents and voltages, if the power factor of each phase is not kept near the same value, and is not recommended.

5. Operation, Testing, and Repair

There is a seasonal variation in load and in KVAR demand on most of the individual feeders and on the system as a whole. In the spring, as the weather gets warmer, the load begins to increase due primarily to increased air conditioner loads. During this time, the system requires additional capacitor banks to be turned on. The amount of capacitors turned on is based on the projected load for that summer. In the fall of the year, as the load begins to decrease due to cooler weather, the required amount of capacitor banks decreases according to the load. The power factor set by Power Supply will determine the amount of vars required to satisfy the system at these variable seasons.

Capacitor banks are sometimes installed close to large three phase motors. If the installation is such that the capacitors and motors may be separated from the line and other area load by a three phase switch, take care to see that the capacitors are not of a value that would permit the motors to run as self excited induction generators if separation occurred. The capacitor current must be no more than the no-load current of the motor at rated voltage. Larger capacitor currents could cause a running induction motor to use it's inertia to act as a self excited induction generator. Generated voltages could go up to about 150 percent of normal. See also NEC, Article 460-7; Westinghouse Transmission and Distribution Reference Book, 4th Edition, page 240, Fig. 11.

B. SECONDARY SHUNT CAPACITORS

FPL began purchasing and using secondary capacitors in 1952. The most common sizes purchased were 3, 5, 7 and 15 kVAR. In the mid-1960's, economics, along with the use of PCB's, made new purchases of secondary capacitors unattractive.

FPL no longer purchases secondary capacitors. In 1983, a program was created to locate and identify secondary capacitors and they were removed.

C. PRIMARY SERIES CAPACITORS

Shunt capacitors are used extensively throughout the FPL Distribution Systems. Their beneficial effects are desirable at practically all points in the system and their installation and operation is reasonably simple. In contrast, series capacitors are very seldom used on the FPL Distribution System. Their benefits are practical for only a limited range of applications. Series capacitors are, however, particularly suited to reduce or eliminate voltage fluctuations caused by large induction motors, electric welders, electric arc and induction furnaces.

There are several basic differences in the effects caused by series capacitors as opposed to shunt capacitors. Shunt capacitors are used to compensate for the inductive reactance of the load, while series capacitors compensate for the inductive reactance of the line. Shunt capacitors provide a voltage boost on the line that is relatively independent of the load current. The series capacitor gives a voltage rise which increases as the load current increases. In addition, at lower power factors which would cause more line drop, the series capacitor gives more net voltage rise. For these reasons, the series capacitor may be considered as a voltage regulator.

The installation and operation of a series capacitor bank is complicated by several factors. The location, size and rating of the bank is critical. Ferroresonance and sub-synchronous resonance may occur under certain conditions. Special protective devices are required to protect the series capacitors from overvoltage and fault current. A detailed analysis of the feeder circuit is required to insure proper operation.

Series capacitors have also been used in the primary neutral lead of individual transformers. For inductive loads, they act as a regulator for that particular transformer. They have some of the same application and protection problems as primary series capacitors. This has prohibited their general use on most distribution systems.

Should the need for a series capacitor be considered, please consult your Reliability Planning Engineer.

HANDY FORMULAS

PRIMARY VOLTAGE DROP:

% VOLTS DROP

$$\frac{I\ (R \cos\varphi + X \sin\varphi)}{V} \times 100$$

WHERE: V = Phase to neutral voltage, source end.

I = Line current in AMPS

R = Line resistance in OHMS

X = Line reactance in OHMS

φ = Power factor angle in degrees, at source.

VOLTAGE RISE DUE TO CAPACITORS:

% VOLTS RISE =

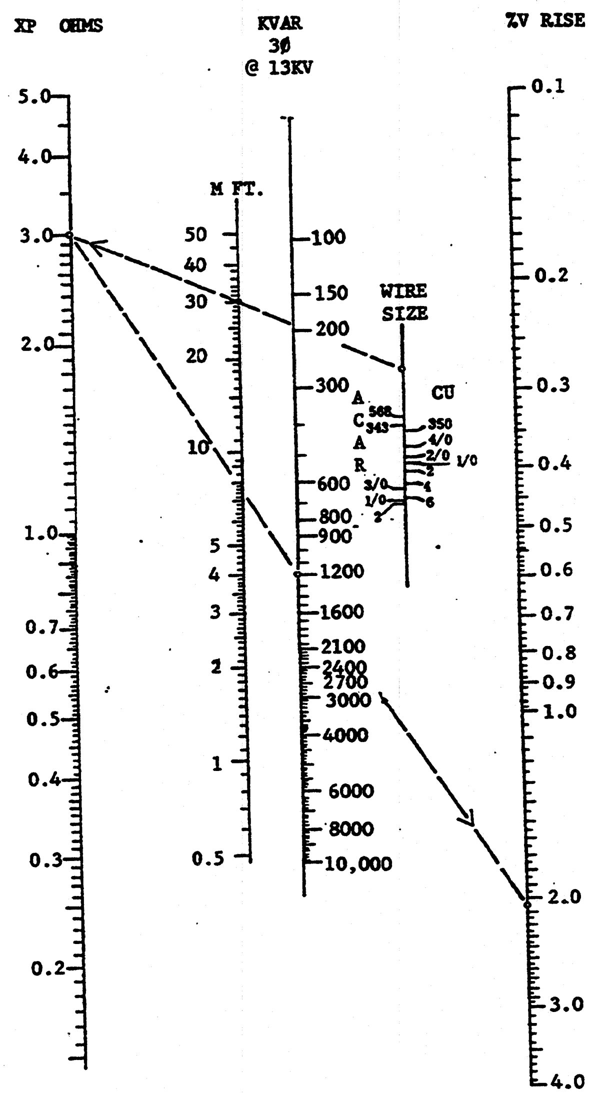
This formula is an approximation, but quite accurate for the range of values encountered in distribution systems. See also Fig. 10. The accumulated values for "R" and "X" can be taken directly from the line section data fault current print-out.

For three phase lines: R = Rp , X = Xp

For single phase lines: R = Rq , X = Xq

CAPACITOR BANK PHASE CURRENT:

$$Ic = \frac{\textit{KVAR PER PHASE}}{\textit{KV PASE TO NEUTRAL}}$$



VOLTAGE RISE PRIMARY CAPACITORS
13kV SYSTEM

INSTRUCTIONS

Determine wire size and distance from substation to location of capacitor bank. From proper wire size on "WIRE "SIZE" scale, draw a straight line to proper "Mft." point on "M Ft." scale. Continue this line to intersect "Xp ohms" scale. From this point of intersection, draw a straight line through the proper point on "KVAR, 3φ, @ 13KV" scale, extending to intersect the "% V Rise" scale. The point of intersection gives the percent voltage rise.

NOTE: This chart may also be used for 3φbanks at 23KV if the percent rise as obtained above is divided by 3.

2.1.4 PRIMARY AND/OR SECONDARY FAULT CURRENT AT POINT OF SERVICE

A. GENERAL

When designing a customer's building wiring, whether it is a residential, commercial or industrial customer, the engineer will always give the main service entrance breaker or fused entrance switch special attention. This switch or breaker is the customer's "last ditch" defense against disabling damage which might be initiated by the failure of a piece of equipment or a circuit conductor. If the fuse or breaker on the branch circuit feeding the failed equipment does not clear the fault, the service entrance breaker must.

The service entrance equipment must be able to carry the load, and also successfully interrupt the short circuit current which might develop on the circuits.

The customer or his engineer needs to know the magnitude of short circuit current which our system is capable of delivering to the customer. Using this information, together with other data he has on the customer's system, he can select the proper service entrance device and the fault current rating of all of their switchgear.

FPL must cooperate and furnish the information to the best of its ability. In doing so, judgement must be exercised. Precise determination of available fault current for a given proposed installation is not possible. The value given to the consultant should be based on the instructions given on this section, and should be carefully reviewed in order to avoid excessive expenses to the customer since providing a higher number than recommended by these instructions may cause the specification of higher cost breakers or additional equipment by the customer. On the other hand, if the value of available fault current given is lower than these instructions recommend, then the customer's equipment could fail to interrupt a fault. This is possible if the conditions are changed either before or after the installation is completed.

At the same time, our policy to provide primary and /or secondary fault current to our customers considers the impact of the fault current contribution from other generating sources, such as Renewable Energy Interconnections.
A few examples of the conditions that can be changed, either by the customer or by FPL, are shown below.

B. POSSIBLE CHANGES BY CUSTOMER

1. The customer may have increased load. This could require FPL to increase the transformer capacity, which will usually sharply increase the available fault current.

2. The customer could make significant design changes after early negotiations with FPL. These changes might not be communicated until after building construction begins -- or is nearly completed. This could require FPL to install different equipment to serve the load. This changes the conditions from those upon which the fault current was determined.

C. POSSIBLE CHANGES BY THE FLORIDA POWER & LIGHT COMPANY

1. FPL could install a different transformer than the one on which the fault current was calculated. This could result from any of the following reasons:

   1. The load demand could exceed original estimates, requiring a larger transformer.
   2. The transformer could fail, and be replaced with a lower impedance or larger transformer.
   3. The proposed transformer might not be available at the time of construction, and another transformer of greater kVA or lower impedance might be installed.

   Any of the above cases could produce a higher fault current than was calculated.

The primary circuit and/or source impedance could be lowered by any of the following:

1. The feeder could be re-conductored.
2. A new substation could be built and the feeder shortened.
3. A larger substation transformer could be installed.
4. The line section feeding the customer could be switched to a "stiffer" feeder.
5. The primary voltage of the circuit could be converted to a higher voltage.

Any of the previous items could produce a higher primary or secondary voltage fault current than was calculated. This is the reason why we provide the maximum FPL substation design to our customers, and we incorporate as well the maximum fault current contribution from Interconnections.

D. ADDITIONAL FACTORS TO CONSIDER

1. Asymmetrical Current

The nature and causes of asymmetrical currents are too lengthy to be condensed in this discussion. However, for those persons interested, an excellent brief of the subject is contained in the General Electric Company publication, "Industrial Power Systems Data Book," Section 0.10, Pages 6 through 11

In general, it is not practical to state fault currents in asymmetrical values to consultants. Boundary conditions necessary for calculations are difficult, and sometimes impossible, to determine in advance. Further, these conditions will likely change due to frequent alterations in the primary supply system.

Asymmetrical values could be as high as 1.5 times symmetrical fault current at the distribution substation feeder pulloff. (See DERM Section 2.1.2 page 2)

2. Motor Contribution to a Fault

The additional current supplied to a fault by customer's motors must be added to the fault current produced by the supply system. Qualified consultants use their own methods to determine motor fault contribution. Thus, it is both unnecessary and undesirable to include this contribution in the values supplied to the consultant.

4. Transformer Characteristics

The combination of KVA and impedance of the transformer(s) serving the customer has an effect on the available fault current. Care must be exercised that fault current figures given to the consultant are based on the correct transformer(s).

The percent impedance of distribution transformers on the Florida Power & Light system varies for a given type, i.e., M & S number. This is mainly because the transformers were purchased over a period of years during which technology and industry standards were changing. Therefore, fault current calculations should be made based on using the most accurate impedance for a transformer of a given type.

5. Transformer Calculations for X & R values

If the transformer KW losses are known, the impedance may be separated into its reactive (X) and resistive (R) values.

$$R = \frac{Load\ Losses}{(10)(TX\ kVA)}$$

Example: A 1,500 kVA transformer has impedance (Z) of 5.31% and KW losses of 7.944 KW at full rated capacity. Calculate X and R values.

$$R = \frac{Load\ Losses}{(10)(TX\ kVA)} = \frac{7944}{(10)(1500)} = 0.5296 = 0.53\%$$

$$X = \sqrt{(Z^2) - (R^2)}$$

$$X = \sqrt{(Z^2) - (R^2)} = \sqrt{(5.31)^2 - (0.53)^2} = 5.28\%$$

E. GUIDELINES FOR RELEASING FAULT CURRENT INFORMATION TO CONSULTANTS

(Release of fault current information to the customer or consultant is done only in writing as shown in Service Planning operations procedure 21010.6 page 3)

A. Fault Current at the Primary Voltage Level

The Planning Dept should be consulted at all times for any customer requests of fault current at the Primary Voltage level. (For example: Primary meter installations with customer switchgear exposed to Primary voltage, dedicated feeders serving large loads, Interconnections, etc.)

1. Requests from Regular Customers:

The FPL distribution primary supply system has a maximum fault current capability of 6700 Amps of three phase and 4000 Amps of single phase to ground symmetrical amps.

However, our policy allows Renewable Energy Generators to interconnect on the distribution system as long as their available three phase (and/or phase to ground) fault current is 1600 Amps or less. This needs to be considered in order to ensure that all customers size their Primary Voltage switchgear with enough fault current capability considering both, the contribution from the FPL system and the contribution from an existing or future Renewable Energy Interconnection facility.

Therefore, the Planning Dept should provide the following fault current values to customers requesting fault current values at the Primary Voltage level (13 KV or 23 KV):

3 phase symmetrical fault current = 8300 Amps @ 13KV or @ 23KV

Phase to Ground symmetrical fault current = 6000 Amps @ 13KV or @ 23 KV (see note)

Note: The combination of the FPL and Generator's phase to ground fault current cannot be added directly as 4000A + 1600A = 5600A because of paralleling of the zero sequence impedances. However, using fault current symmetrical component analysis, the resulting phase to ground fault current is approximately 6000 Amps.

2. Requests from Renewable Interconnection Customers (Size 2 to 20 MW)

(Communications are done via the Renewable Interconnections Project Manager)

The Planning Dept should advise that the maximum fault current contribution from the FPL Primary feeder system, without considering the contribution from the Interconnection in question or any other sources is:

*3 phase symmetrical fault current = 6700 Amps @ 13KV or @ 23KV

*Phase to Ground symmetrical fault current = 4000 Amps @ 13KV or @ 23 KV

*Note: If there is already another existing Interconnecting facility in the substation area, the planning engineer should provide the FPL 6700A/4000A fault current values plus the available 3 phase and phase to ground fault current numbers from the existing Interconnecting facility.

The Interconnection customer can utilize these numbers, along with their own fault current Generation, to size their Primary Voltage switchgear.

The Interconnection customer must supply to Distribution Planning the 3 Phase and Phase to Ground fault current capability of their Generating facility for a fault at the FPL Primary service point (13 KV or 23 KV), independent of the FPL system, that is, assuming that the FPL feeder service is disconnected. (Open switch)

B. Fault Current at the Secondary Voltage Level

1. Service Planners can provide the fault current at the Secondary Voltage level to customers using the tables at the end of this text. The tables have been updated considering the maximum available fault current capability of the FPL primary voltage distribution system including the fault current capability of any existing or future Interconnection generating facility.
2. The size and type of transformer(s) that will be installed must be known before fault current information is released. If there is any possibility that a larger KVA capacity transformer may be installed in the future, fault current should be based on the larger transformer.
3. For special customer requests, for example, customer requests for feeder breaker relay data, or special cases not included on the tables, for example, large transformer installations connected in parallel, or transformer types not shown on the tables, etc., consult the Planning Department.

C. Arc Flash Requests

Due to the new OSHA Regulation concerning Arc Flash that was put in effect on January 1, 2009, customers are now requesting information from FPL to conduct their Arc Flash analysis.

In general, an arc flash is produced when the amount of impedance in the short circuit connection to ground or to another phase in the power system is low. The energy dissipated on the arc flash depends, among other factors, on the amount of fault current and the clearing time (breaker or fuse) of the protective devise involved.

FPL does not provide arc flash calculations to the customers, but we are allowed to provide:

- The FPL available fault current information as described under this section.
- Information concerning the FPL protective device at the customer's location.

Service Planners can provide the FPL secondary voltage fault current information as usual, plus information concerning the transformer fuse (size & type) protecting the service transformer using the Fault Current Disclosure letter. Upon special request, the KVA size and the percent impedance of the transformer can be provided as well.

On projects involving large customers served by Primary Voltage, (Primary Meters with primary voltage customer switchgear, Interconnections, dedicated feeders, etc.) the protective device may be the feeder breaker/relay, a field recloser, or fuse switches. In this case, the Area Planning Engineer provides the fault current information (See "Guidelines for releasing fault current information to consultants - Fault Current at the Primary Voltage Level items 1 & 2 and the feeder relay/recloser or fuses protective devise data to the Service Planner to be included on the Fault Current Disclosure letter.

D. RELEASE OF FAULT CURRENT INFORMATION TO THE CUSTOMER OR CONSULTANT IS DONE ONLY IN WRITING AS SHOWN IN SERVICE PLANNING OPERATIONS PROCEDURE 21010.6 PAGE 3. The following are the official tables to be used when providing secondary voltage fault currents to customers.

SECONDARY FAULT CURRENT AT POINT OF SERVICE

208Y/120 VOLT 3 PHASE SECONDARY

Transformer Description				Transformer Impedances	Amps @ 208 Volts 3 Phase With 3 Phase Fault Current of 8300 Amps (Maximum Available on Distribution Primary)	
kVA	Type	Primary Voltage	Secondary Voltage	Z%	With Transformer Energized @ 13kV	With Transformer Energized @ 23kV
112.5	3-1ph Aerial	7620/13200Y	208Y/120	1.45%	20,690	------------
112.5	3-1ph Aerial	13200/22860Y	208Y/120	1.64%	------------	18,652
112.5	3-1ph Aerial	7620/13200Y x 13200/22860Y	208Y/120	1.71%	17,649	17,903
150	3-1ph Aerial	7620/13200Y	208Y/120	1.60%	24,797	------------
150	3-1ph Aerial	7620/13200Y x 13200/22860Y	208Y/120	1.60%	24,797	25,301
150	3-1ph Aerial	13200/22860Y	208Y/120	1.60%	------------	25,301
150	3ph Padmount	7620/13200Y x 13200/22860Y	208Y/120	3.30%	12,322	12,445
150	3ph Padmount	13200/22860Y	208Y/120	3.30%	------------	12,445
225	3-1ph Aerial	7620/13200Y	208Y/120	1.60%	36,341	------------
225	3-1ph Aerial	7620/13200Y x 13200/22860Y	208Y/120	1.60%	36,341	37,432
225	3-1ph Aerial	13200/22860Y	208Y/120	1.60%	------------	37,432
300	3ph Aerial	7620/13200Y	208Y/120	3.50%	22,764	------------
300	3ph Aerial	7620/13200Y x 13200/22860Y	208Y/120	3.50%	22,764	23,187
300	3ph Padmount	7620/13200Y	208Y/120	3.50%	22,764	------------
300	3ph Padmount	7620/13200Y x 13200/22860Y	208Y/120	3.50%	22,764	23,187
300	3ph Padmount	13200/22860Y	208Y/120	3.50%	------------	23,187
300	3-1ph Aerial	7620/13200Y	208Y/120	1.65%	46,055	------------
300	3-1ph Aerial	7620/13200Y x 13200/22860Y	208Y/120	1.65%	46,055	47,822
300	3-1ph Aerial	13200/22860Y	208Y/120	1.65%	------------	47,822
500	3ph Aerial	7620/13200Y	208Y/120	4.00%	32,552	------------
500	3ph Aerial	7620/13200Y x 13200/22860Y	208Y/120	4.00%	32,552	33,425
500	3ph Aerial	13200/22860Y	208Y/120	4.00%	------------	33,425
500	3-1ph Aerial	7620/13200Y	208Y/120	2.00%	61,315	------------
500	3-1ph Aerial	7620/13200Y x 13200/22860Y	208Y/120	2.00%	61,315	64,488
500	3-1ph Aerial	13200/22860Y	208Y/120	2.00%	------------	64,488
500	3ph Padmount	7620/13200Y	208Y/120	4.00%	32,552	------------
500	3ph Padmount	7620/13200Y x 13200/22860Y	208Y/120	4.00%	32,552	33,425
500	3ph Padmount	13200/22860Y	208Y/120	4.00%	------------	33,425
750	3ph Aerial	7620/13200Y	208Y/120	5.00%	38,586	------------
750	3-1ph Aerial	7620/13200Y	208Y/120	2.00%	86,914	------------
750	3-1ph Aerial	7620/13200Y x 13200/22860Y	208Y/120	2.25%	78,700	84,005
750	3ph Padmount	7620/13200Y x 13200/22860Y	208Y/120	5.25%	36,877	38,001
1000	3ph Aerial	7620/13200Y	208Y/120	5.00%	50,221	------------
1000	3ph Aerial	7620/13200Y x 13200/22860Y	208Y/120	5.00%	50,221	52,330
1000	3-1ph Aerial	7620/13200Y	208Y/120	2.50%	91,700	------------
1000	3-1ph Aerial	7620/13200Y x 13200/22860Y	208Y/120	2.50%	91,700	98,983
1000	3ph Padmount	7620/13200Y x 13200/22860Y	208Y/120	5.50%	46,055	47,822
1500	3-1ph Aerial	7620/13200Y	208Y/120	3.00%	109,844	------------

SECONDARY FAULT CURRENT AT POINT OF SERVICE

480Y/277 VOLT - 3 PHASE SECONDARY

Transformer Description				Transformer Impedances	Amps @ 480 Volts 3 Phase — With 3 Phase Fault Current of 8300 Amps (Maximum Available on Distribution Primary)	
kVA	Type	Primary Voltage	Secondary Voltage	Z%	With Transformer Energized @ 13kV	With Transformer Energized @ 23kV
150	3ph Padmount	7620/13200Y	480Y/277	3.30%	5,339	------------
150	3ph Padmount	7620/13200Y x 13200/22860Y	480Y/277	3.30%	5,339	5,393
150	3ph Padmount	13200/22860Y	480Y/277	3.30%	------------	5,393
150	3-1ph Aerial	7620/13200Y	480Y/277	1.60%	10,746	------------
150	3-1ph Aerial	13200/22860Y	480Y/277	1.70%	------------	10,336
225	3-1ph Aerial	7620/13200Y	480Y/277	1.60%	15,748	------------
300	3ph Padmount	13200/22860Y	480Y/277	3.50%	------------	10,048
300	3ph Padmount	7620/13200Y x 13200/22860Y	480Y/277	3.50%	9,864	10,048
300	3-1ph Aerial	7620/13200Y	480Y/277	1.60%	20,525	------------
300	3-1ph Aerial	13200/22860Y	480Y/277	1.60%	------------	21,336
500	3ph Aerial	7620/13200Y	480Y/277	4.00%	14,106	------------
500	3ph Aerial	7620/13200Y x 13200/22860Y	480Y/277	4.00%	14,106	14,484
500	3ph Padmount	7620/13200Y	480Y/277	4.00%	14,106	------------
500	3ph Padmount	7620/13200Y x 13200/22860Y	480Y/277	4.00%	14,106	14,484
500	3ph Padmount	13200/22860Y	480Y/277	4.00%	------------	14,484
500	3-1ph Aerial	7620/13200Y	480Y/277	2.00%	26,570	------------
500	3-1ph Aerial	13200/22860Y	480Y/277	2.00%	------------	27,945
750	3ph Aerial	7620/13200Y	480Y/277	4.75%	17,533	------------
750	3ph Aerial	7620/13200Y x 13200/22860Y	480Y/277	4.75%	17,533	18,121
750	3ph Padmount	7620/13200Y x 13200/22860Y	480Y/277	5.25%	15,980	16,467
750	3ph Padmount	7620/13200Y	480Y/277	5.25%	15,980	------------
750	3-1ph Aerial	7620/13200Y	480Y/277	2.00%	37,663	------------
750	3-1ph Aerial	13200/22860Y	480Y/277	2.00%	------------	40,486
1000	3-1ph Aerial	13200/22860Y	480Y/277	2.00%	------------	52,200
1000	3ph Padmount	7620/13200Y x 13200/22860Y	480Y/277	5.25%	20,821	21,656
1000	3ph Aerial	7620/13200Y OR 13200/22860Y	480Y/277	4.85%	22,370	23,336
1500	3ph Aerial	7620/13200Y	480Y/277	5.00%	31,158	------------
1500	3ph Aerial	7620/13200Y x 13200/22860Y	480Y/277	5.00%	31,158	33,066
1500	3-1ph Aerial	7620/13200Y	480Y/277	2.30%	58,380	------------
1500	3-1ph Aerial	13200/22860Y	480Y/277	2.30%	------------	65,456
1500	3ph Padmount	7620/13200Y x 13200/22860Y	480Y/277	5.50%	28,682	30,291
2000	3ph Padmount	7620/13200Y x 13200/22860Y	480Y/277	5.65%	35,884	38,438
2000	3ph Aerial	7620/13200Y x 13200/22860Y	480Y/277	5.00%	39,737	42,893
2500	3ph Padmount	7620/13200Y x 13200/22860Y	480Y/277	5.70%	42,851	46,544

SECONDARY FAULT CURRENT AT POINT OF SERVICE

240 VOLT Δ - 3 PHASE SECONDARY

Transformer Description				Transformer Impedances	Amps @ 240 Volts 3 Phase — With 3 Phase Fault Current of 8300 Amps (Maximum Available on Distribution Primary)	
					With Transformer Energized @	
kVA	Type	Primary Voltage	Secondary Voltage	Z%	13kV	23kV
112-1/2	3-1ph Aerial	7620/13200Y	240 D	1.45%	17,931	- - - - - -
112-1/2	3-1ph Aerial	13200/22860Y	240 D	1.64%	- - - - - -	16,165
112-1/2	3-1ph Aerial	7620/13200Y x 13200/22860Y	240 D	1.71%	15,296	15,516
150	3-1ph Aerial	7620/13200Y	240 D	1.52%	22,566	- - - - - -
150	3-1ph Aerial	13200/22860Y	240 D	1.70%	- - - - - -	20,671
150	3-1ph Aerial	7620/13200Y x 13200/22860Y	240 D	1.78%	19,410	19,765
225	3-1ph Aerial	7620/13200Y	240 D	1.41%	35,410	- - - - - -
225	3-1ph Aerial	13200/22860Y	240 D	1.87%	- - - - - -	27,923
225	3-1ph Aerial	7620/13200Y x 13200/22860Y	240 D	1.56%	32,246	33,238
300	3-1ph Aerial	7620/13200Y	240 D	1.44%	45,159	- - - - - -
300	3-1ph Aerial	7620/13200Y	240 D	1.56%	- - - - - -	43,705
300	3-1ph Aerial	7620/13200Y x 13200/22860Y	240 D	1.65%	39,914	41,446
500	3-1ph Aerial	7620/13200Y	240 D	1.89%	55,854	- - - - - -
500	3-1ph Aerial	13200/22860Y	240 D	1.93%	- - - - - -	57,769
500	3-1ph Aerial	7620/13200Y x 13200/22860Y	240 D	1.88%	56,115	59,190

SECONDARY FAULT CURRENT AT POINT OF SERVICE

240/120 VOLT - SINGLE PHASE SECONDARY

Transformer Description (Single Phase)				Transformer Impedances	Amps @ 240 Volts With Phase-Ground Fault Current of 6000 Amps (Maximum Available on Distribution Primary)	
kVA	Type	Primary Voltage	Secondary Voltage	Z%	With Transformer Energized @ 7620/13200Y	With Transformer Energized @ 13200/22860Y
25	Aerial	13200/22860Y	120/240	1.45%	- - - - - -	12,178
25	Aerial	7620/13200Y x 13200/22860Y	120/240	1.45%	11,991	12,178
37.5	Aerial	13200/22860Y	120/240	1.65%	- - - - - -	15,944
37.5	Aerial	7620/13200Y x 13200/22860Y	120/240	1.65%	15,625	15,944
50	Aerial	13200/22860Y	120/240	1.60%	- - - - - -	21,697
50	Aerial	7620/13200Y x 13200/22860Y	120/240	1.60%	21,110	21,697
75	Aerial	7620/13200Y	120/240	1.60%	30,684	- - - - - -
75	Aerial	13200/22860Y	120/240	1.60%	- - - - - -	31,939
75	Aerial	7620/13200Y x 13200/22860Y	120/240	1.60%	30,684	31,939
100	Aerial	7620/13200Y	120/240	1.65%	38,620	- - - - - -
100	Aerial	13200/22860Y	120/240	1.65%	- - - - - -	40,630
100	Aerial	7620/13200Y x 13200/22860Y	120/240	1.65%	38,620	40,630
167	Aerial	7620/13200Y	120/240	1.90%	53,205	- - - - - -
167	Aerial	13200/22860Y	120/240	1.90%	- - - - - -	57,096
167	Aerial	7620/13200Y x 13200/22860Y	120/240	1.90%	53,205	57,096

2.1.6 PLANNING

A. GENERAL - DESIGN AND CAPABILITIES

Distribution system planning is a process by which the FPL's distribution system is expanded in an orderly and economic manner to meet the load growth and reliability requirements. Planning the distribution system is an art and a science. It requires an understanding of FPL's standards, past and present past usage of materials in the field, detailed knowledge of the distribution system being planned and solid computer and analytical skills to evaluate the strengths and weaknesses. It is cross-functional because it requires close coordination with many groups within FPL including service planners, designers, operations, substation and transmission engineering, system planning and land management.

First, to understand planning, we must first look at the basic design and capabilities of the FPL distribution system. This section covers basic substation and feeder design, equipment ratings and reliability goals.

1. System Configuration

a. Substations

Distribution substations tap into the transmission system and step down the voltage from 69kV, 115kV, 138kV or 230kV to distribution voltage, usually 13kV or 23kV. Most stations are designed with a looped transmission feed so that the loss of an individual transmission line section does not take the station out of service. Generally, a station will have two or more station transformers sized such that the station can operate under emergency conditions even with the loss of one of the transformers. Each transformer feeds a section of the distribution operating bus. These sections can be tied together in an emergency should one of the transformers be lost. In some cases, however, where the station has only one or two feeders, a single transformer may be used with a mobile connection

Typical station configurations are:

1. Single Transformer - Capacity is limited to the mobile transformer capacity (20 or 35 MVA). Loss of the single station transformer usually requires that a mobile be rolled within 12 hours. Until the mobile arrives, backup capability can be provided from feeders at other stations if the distribution grid is strong enough.
2. Two Transformers - This is the most common arrangement for stations with two three to six feeders. The station operates in the split bus mode. Should a transformer be lost, the operating bus can be tied and the entire station load can be placed on one transformer. Bus-tie breakers are used in many stations to handle this function automatically. Care should be taken to assure the emergency rating of the transformer is not exceeded. Remaining load, up to its capacity, will be served by the mobile transformer when it is installed.

In some cases a station may have two station transformers which are served radially from two separate transmission lines. Should one line fail, automatic load transfer is accomplished by motorized switches on the operating bus. The operating bus is normally split. However, there are cases where the entire operating bus is fed from one transformer. This is usually done if one of the transmission sources is subject to frequent interruptions. In this case one transformer operates as a standby backup to the other.

3. Three or more Transformers - Used in larger stations that have more than five or six feeders. When the load and number of feeders exceeds the emergency rating of the smaller of two station transformers, a third transformer is usually added. Each transformer feeds a section of the operating bus. Should one of the station transformers be lost, the bus can be tied with the other transformers picking up the load. Check to see that equipment fault current limitations are not exceeded.

The efficiency of these various arrangements is shown in Table 1 which gives the percent of total installed nameplate capacity that can be utilized while still maintaining emergency capability. This assumes permissible emergency loading of up to 130% summer or 150% winter, of the nameplate rating.

TABLE 1
TRANSFORMER UTILIZATION

		TWO TRANSFORMERS		
STATION TYPE	SINGLE TRANS.	SPLIT BUS	TIED BUS	THREE TRANS.
Utilization Per-Cent Installed Capacity	100%	65% - S 75% - W	65% - S 75% - W	87% - S 100% - W

∗Depends on backup capability being available on feeders from adjacent substations

S – Summer loading
W – Winter loading

Other station operating features include the inspection breaker and inspection bus that provides backup breaker capability for each feeder. Any feeder can be operated from the inspection bus, utilizing the inspection breaker thereby allowing the normal feeder breaker to be taken out of service for repair or maintenance.

Most stations are equipped with supervisory control. This remote control feature provides status indication of all critical functions and provides remote operating capability for transmission switches, feeder breakers, regulator blocking, etc. All feeders now have feeder telemetry including voltage and current by phase as measured at the regulators.

Typical station configurations are shown in Figures 1-4.

b. Feeders

Distribution feeders originate at the substation breaker and have a radial (no loops) configuration. The overhead distribution system is, however, basically a grid of line sections which are separated by disconnect switches. Feeder configuration is established by opening disconnect switches (manual or automatic) and eliminating any loops which might exist. Radial operation is necessary in order to establish a practical over-current protection scheme. The multiple tie capabilities available from the grid type system provide alternate feeds necessary to minimize the area of an outage due to a permanent fault.

Feeders consist of the main "backbone" three-phase line that is part of the overall grid, and radial lateral runs that branch off of the main feeder. These radial runs may be three-phase, or fused single and two-phase lines.

Feeder mains are sized for normal loads and to provide emergency relief to other feeders. Feeder mains should have a minimum wire size of 343 T. Use of smaller sizes of wire as part of the interconnected grid creates bottlenecks in the system, and often prevents full utilization of a feeder's capacity. In general, most feeders have an emergency capacity at the station that exceeds the thermal limit of 343 T. In order to standardize on one wire size, 568 T is the only overhead wire sizes used for feeder main.

The grid of feeder mains usually develops along major through streets or section lines. Lines are occasionally placed in rear easements but this usually results in increased operation and maintenance problems. Accessibility to disconnect switches in a rear easement can delay restoration. The basic grid spacing, while traditionally at one-mile intervals initially, is primarily dependent on load density. Generally as load grows, the grid will fill in and become more compact.

Laterals, (1Ø, 2Ø & 3Ø) are line sections that branch off of the main grid, and are usually #3/0T or #1/0T. A lateral should only be extended into areas whose ultimate load is not expected to exceed 1.5 to 2.0 MVA and where no ties to other feeder sections are anticipated. It would be a mistake to bring 3Ø #3/0T into an area which eventually will grow to the point that requires it to be reconductored to establish a feeder main. A little advanced planning will prevent this costly mistake.

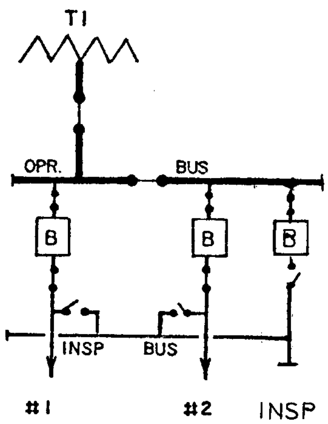


FIGURE 1

SINGLE TRANSFORMER STATION

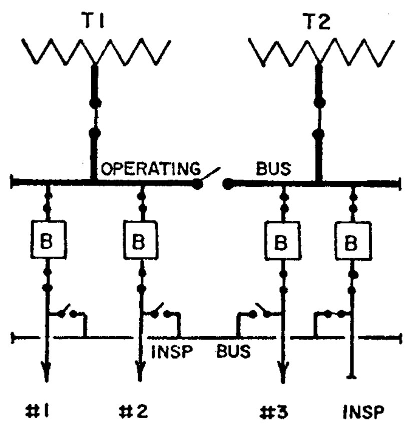


FIGURE 2

TWO TRANSFORMER STATION

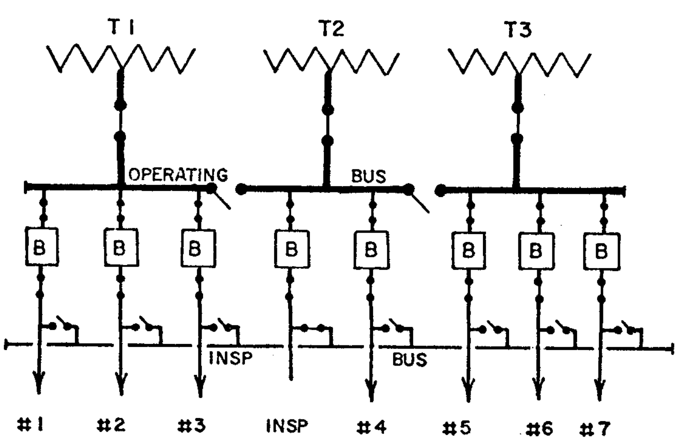


FIGURE 3

THREE TRANSFORMER STATION

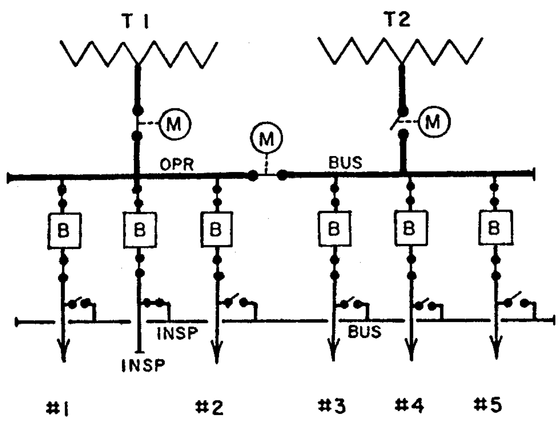


FIGURE 4

TWO TRANFORMER STATION
WITH TIED OPERATING BUS

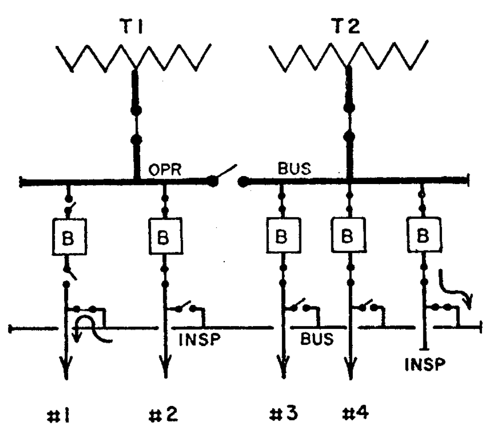


FIGURE 5

UTILIZATION OF THE INSPECTION BUS

Long rural lines require special consideration. Low voltage and fuse coordination problems often arise with the use of the smaller conductor sizes so 568 T is still the conductor of choice. Where the load is light and load growth is low, conductor sizes smaller than 343 T can be tolerated.

Feeder mains are increasingly being placed underground, especially in large URD subdivisions. Feeder pulloffs can be 1000 kcmil A or C XPE cable in conduit. Nearly twice as expensive, copper is usually reserved for very special situations such as higher winter loading or a duct system. These require careful judgement and justification. Underground sections are switched the same as overhead lines. Loads are not normally connected directly to these underground sections, except in URD subdivisions where switch cabinets are used to tap URD laterals.

Submarine feeder sections usually utilize 3-conductor copper submarine cable in sizes of 500 kcmil and 750 kcmil.

c. Distribution Voltages

Distribution voltages being utilized are 4kV, 13kV, and 23kV. The 4kV systems are load limited and are mostly phased out. They are primarily confined to small geographic areas, usually in older sections. 13kV is our standard distribution voltage, and makes up the bulk of the distribution system. Rural areas that are not yet heavily developed are generally designated as 23kV areas, and are being designed accordingly. Such areas now fed at 13kV will be converted to 23kV when the 13kV system is unable to serve the load. This occurs when the 13kV feeder becomes voltage or fault current limited.

Voltage conversion is of particular benefit since the load capability on a voltage-limited feeder varies as the square of the voltage. For a current-limited feeder the load capability varies directly proportional to the voltage.

Pad-mounted, 11.2 or 15 mVA autotransformers are used for transitioning between 13kV and 23kV. When located at a substation, it allows 23kV feeders to be established at 13kV substations or vice versa. When located in the field, they provide for voltage transition between the 13kV and 23kV feeders. Their location needs to be reviewed closely to ensure that the device does not become a weak link in the system.

2. Equipment Ratings

There are two basic equipment ratings that are used in system design and planning. One is the manufacturer's nameplate rating and the other is the company's emergency rating.

The nameplate rating represents the load that can normally be applied to a device, day after day without any appreciable loss of life. The company's emergency ratings are derived for a period not to exceed two hours. This rating is based on an acceptable amount of deterioration for each emergency.

a) Equipment ratings are given in the following references:

1. Power System Capacity Guidelines

2.a) "Primary Overhead Distribution Conductor Current Carrying Capacities" by the Power Systems Distribution Construction Standards(P.S.D.C.S.) F7.0.0

3.b) "Allowable Short-Time Emergency Loading", Distribution Equipment - Regulators - DERM, Section 3.8, p.8.

4.c) Primary Cable Ampacities as periodically distributed by the Power Systems Distribution Construction Standards UV15.0.5-UV-15.1.3

b) Emergency ratings may be summarized as follows:

5.2. Substation Equipment - These ratings are usually expressed in per-cent of nameplate rating for a short period not to exceed two hours.

i.a)Station Transformers-130% first load cycle then 115% (Summer Loads) 150% (Winter Loads)

ii.b) Station Breakers -usually 110%

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iii.c) Current Transformers-usually 125%

iv.d) Reactors (varies) -125% to 150%

v.e) Disconnect Switches- usually 110%

vi.f) Regulators- usually 150%

6.3. Overhead Conductors - Emergency rating should be the thermal limit as given P.S.D.C.S. F7.0. Other factors such as sag and voltage drop may also have to be taken into account.

7.4. Cables - Deriving both Normal and Emergency ratings is a complex process since there are so many variables.

Ratings are usually based on either the maximum conductor temperature or the maximum earth interface temperature. Variables include ambient temperature, conductor spacing, neutral configuration, soil thermal conductivity, wet or dry conditions, number or circuits in close proximity, type of duct, load factor, duration of overload, etc.

Primary Cable ratings are given in the P.S.D.C.S. UV15.0.5-UV-15.1. (13 sheets) and the Power System Capacity Planning Guidelines, pages 34-35.

Multiple circuits in duct banks must be de-rated as shown in UV-15.0.5 This is due to the cumulative heating effect of all circuits in operation. Only the circuits that are loaded at a given time need to be considered, however. If a duct bank had three cable circuits, but one was out of service and being backed up by one of the other two, the emergency capacity of the relieving cable would be based on two circuits in the duct bank, not three.

3. System Reliability Goals

The discussion of system configuration has illustrated, in most cases, our basic goals for system reliability. The following summary is given in order to clearly establish those goals, as they now are being applied. Of course, these goals will always be influenced by economic factors. A balance between reliability and economics must always be attained. Economic factors will occasionally require deviation from these guidelines.

a. Substation Equipment

System design should be such that loss on any single item of equipment at the substation or feeder level will not result in a permanent interruption of service to customers. This would include loss of such items as substation transformers and breakers. This requirement is usually satisfied by multiple station transformers and the inspection breaker/bus arrangement. Voltage regulators are not considered absolutely essential and may be bypassed in an emergency. Normally, however, a feeder could be picked up by adjacent feeders in the event of regulator failure.

b. Substation Pulloffs

A "pulloff" is defined as the section of cable or overhead conductor that connects the feeder position in the substation to the overhead or underground distribution system. Loss of a pulloff is especially critical since it takes the entire feeder out of service. Underground pulloffs are of particular concern since they can take many hours or even days to repair.

System design should be such that loss of a pulloff will not result in a permanent interruption of service to a feeder. Normally, this can be achieved by switching the out-of-service feeder to adjacent feeders in the area. Ample emergency capacity must be available on adjacent feeders, with suitable ties available to accomplish this switching. In some cases this requirement is satisfied by having an alternate, or spare pulloff for a feeder.

c. Underground Feeder Sections

Since underground feeder sections, especially river crossings are not readily repaired, an alternate feed should be available to pick up all load normally served by such. The same principles discussed in Par. A 3 b will apply here also.

d. Overhead Feeder Sections

While overhead line sections are more readily repaired than underground, consideration for alternate feeds should be given to those sections which feed appreciable amounts of load.

The overhead distribution system usually forms a grid of inter-connectable line sections. Feeder configuration is determined by open switch points. It is extremely important to limit the amount of load on a switchable line section. This is necessary to limit the area of an outage as well as to facilitate transfer of loads to adjacent feeders. In general, a switchable line section should be limited to around 2.0 mVA of peak load or 230 customers at 13kV and 400 customers at 23kV if at all possible. Sections approaching 3.0 mVA should be split where possible. It is also desirable to have alternate feeds to line sections feeding more than 2.0 mVA for underground and more than 5.0 mVA for overhead. This, however, is not always practical where long radial runs exist in rural areas, or tie routes are not available. A great deal of judgement must be exercised in dealing with these situations.

e. Essential Customer Requirements

Certain customers such as hospitals, airports, etc. require a higher degree of reliability than is normally available on distribution feeders. In this case, throw-over service may be desirable. Several types of throw-over systems are available. All accomplish the same purpose of providing an automatic transfer of load to an alternate feeder. The effect of throw-over systems must be taken into account when making an analysis of emergency conditions, as these loads will automatically be transferred to other feeders until service is restored to the preferred feeder. When throw-over service is provided from overhead feeders, the planning and reliability engineer for the area must be contacted. It should not be taken for granted that sufficient backup capacity exists.

f. Equipment Rating Considerations

System design should assure that normal loads fall within the nameplate ratings (or normal loading limitations on cables) of equipment. There may be cases where minor short time overloads are permitted on transformers, regulators, and conductors due to economic factors. Such factors, however, must be carefully weighed.

System design must also assure that for emergency contingencies, the emergency contingency ratings of equipment, cable and conductors be strictly observed. This applies both to magnitude of load and it's duration.

B. DISTRIBUTION PLANNING PROCESS - INPUTS

A prerequisite for planning is a complete knowledge of the past and present state of the distribution system. From this "data base", trends can be derived and projections be made. The data base consists of both raw and processed data. Raw data includes station and feeder configuration and installed transformer capacity, and capacitor operating history. This data is not always directly usable for planning purposes and must be reduced and analyzed. Various PC-based computer programs are utilized to reduce the data from the Asset Management System. Reduction of substation and feeder load measurements is done by hand. Output data is generated in a form that is directly usable in the planning process. Output data includes load histories and projections, feeder voltage, fault current and reliability analysis, feeder outage analysis and power factor studies etc.

1. Input Data

Input data comes from a variety of sources, each of which will be discussed in detail. The input data forms the basis for determining the present state of the distribution system.

a. Primary & Feeder Maps

Primary and feeder maps contain the information necessary to build an analytical model of the distribution system. This information includes a complete description of line sections including voltage, length, and conductor size and type. Also included are switch locations, connected transformer load, capacitor installations, protective devices, etc. Primary maps incorporate a grid coordinate reference system to facilitate identification of line sections, transformer locations, etc. Primary maps are updated continuously and are available on-line using the TIS system.

b. Capacitor Operating Records

The Radio Controlled Capacitor System (RCCS) controls the vast majority of distribution capacitor banks by monitoring the var flow through the substation power transformers. A turn-on sequence exists for the various capacitors for all feeders on a given power transformer. The RCCS contains a chronological record of capacitor bank switching. A large number of capacitor banks are switched off during periods of light load. Some of this switching is automatic on a daily basis, but many fixed banks are switched on a seasonal basis. When analyzing the power factor of a feeder it is necessary to know the operational status of all capacitor banks on the feeder.

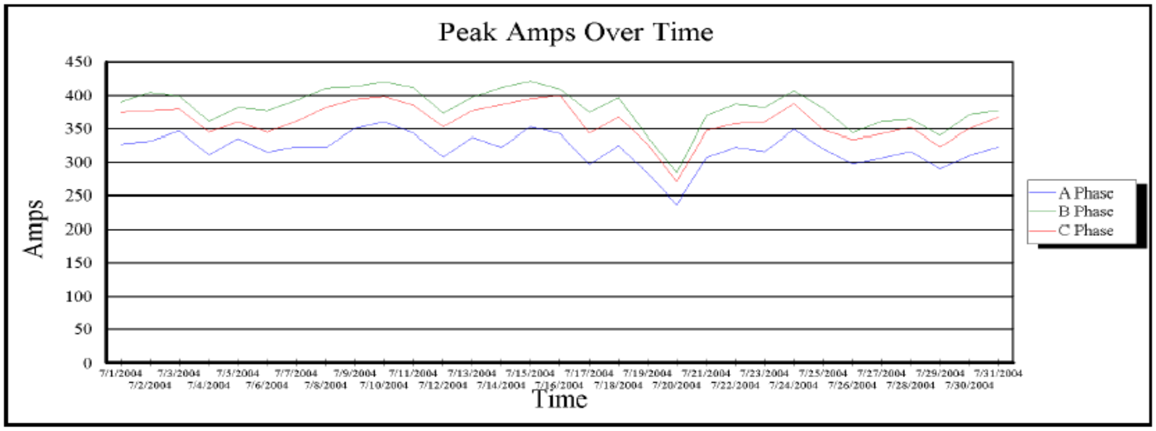
c. Customer Billing Records

These records contain the customer's actual KW demand and are often useful in determining loads on a feeder due to large customers.

d. Substation Metering

FPL has been systematically adding station and feeder telemetry to all substations. Real-time data such as mWs and mVars is available at the power transformer level. This can be seen on Scada monitors in the dispatch offices. It is also available through the Dynamic Peak Amp report in the Data Warehouse. An Access based Feeder Peak Tool is used to analyze the feeder loads to determine the peak and serves as a basis for load histories and projections. Other data is used to monitor station and feeder operating conditions.. See Figure 6A and Figure 6B for sample outputs.

Peak Amp Value Report



Note: Click on any date highlighted in gray to view daily interval details for the corresponding device.

Substation: GOLDEN GATE
Feeder: F504965

Date	Time	A Phase	B Phase	C Phase	High
7/1/2004	3:30 PM	327.797	390.327	374.695	390.327
7/2/2004	4:45 PM	331.705	405.471	377.137	405.471
7/3/2004	2:15 PM	346.361	399.609	380.068	399.609
7/4/2004	1:45 PM	311.676	361.016	344.895	361.016
7/5/2004	1:45 PM	335.613	382.511	360.039	382.511
7/6/2004	4:15 PM	315.584	377.626	344.406	377.626
7/7/2004	3:15 PM	323.400	393.258	361.505	393.258
7/8/2004	4:45 PM	322.912	411.334	382.022	411.334
7/9/2004	3:30 PM	350.269	414.265	394.235	414.265
7/10/2004	2:30 PM	360.528	421.104	398.632	421.104
7/11/2004	2:45 PM	342.941	412.799	385.442	412.799
7/12/2004	2:45 PM	308.256	373.718	353.200	373.718
7/13/2004	3:30 PM	337.079	398.144	377.626	398.144
7/14/2004	3:00 PM	322.423	412.799	386.419	412.799
7/15/2004	3:15 PM	352.711	422.081	395.701	422.081
7/16/2004	3:00 PM	341.964	409.868	400.586	409.868

Figure 6A

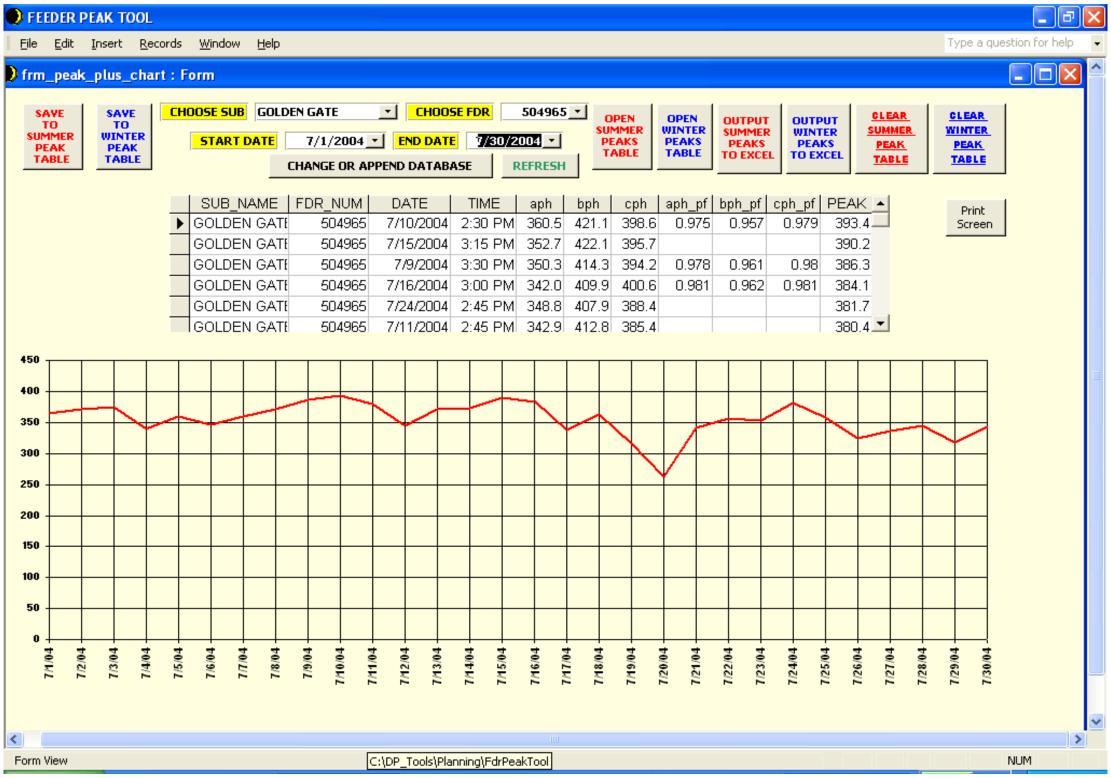

FEEDER PEAK TOOL
File Edit Insert Records Window Help
Type a question for help
frm_peak_plus_chart : Form
SAVE TO SUMMER PEAK TABLE
SAVE TO WINTER PEAK TABLE
CHOOSE SUB
GOLDEN GATE
CHOOSE FDR
504965
START DATE
7/1/2004
END DATE
7/30/2004
CHANGE OR APPEND DATABASE
REFRESH
OPEN SUMMER PEAKS TABLE
OPEN WINTER PEAKS TABLE
OUTPUT SUMMER PEAKS TO EXCEL
OUTPUT WINTER PEAKS TO EXCEL
CLEAR SUMMER PEAK TABLE
CLEAR WINTER PEAK TABLE
Print Screen
SUB_NAME FDR_NUM DATE TIME aph bph cph aph_pf bph_pf cph_pf PEAK
GOLDEN GATE 504965 7/10/2004 2:30 PM 360.5 421.1 398.6 0.975 0.957 0.979 393.4
GOLDEN GATE 504965 7/15/2004 3:15 PM 352.7 422.1 395.7 390.2
GOLDEN GATE 504965 7/9/2004 3:30 PM 350.3 414.3 394.2 0.978 0.961 0.98 386.3
GOLDEN GATE 504965 7/16/2004 3:00 PM 342.0 409.9 400.6 0.981 0.962 0.981 384.1
GOLDEN GATE 504965 7/24/2004 2:45 PM 348.8 407.9 388.4 381.7
GOLDEN GATE 504965 7/11/2004 2:45 PM 342.9 412.8 385.4 380.4
450 400 350 300 250 200 150 100 50 0
7/1/04 7/2/04 7/3/04 7/4/04 7/5/04 7/6/04 7/7/04 7/8/04 7/9/04 7/10/04 7/11/04 7/12/04 7/13/04 7/14/04 7/15/04 7/16/04 7/17/04 7/18/04 7/19/04 7/20/04 7/21/04 7/22/04 7/23/04 7/24/04 7/25/04 7/26/04 7/27/04 7/28/04 7/29/04 7/30/04
Form View
C:\DP_Tools\Planning\FdrPeakTool
NUM

Figure 6B

e. kW-kVar Charts

During the summer months, power quality monitoring equipment such as a Metrosonics or Rustraks can be installed on selected feeders to gain a better understanding of the load and power factor variations over a complete 24 hour period. When precise loading information is needed such as when dealing with a potentially overloaded recloser, load loggers can be installed to monitor the current at selected points on a feeder.

f. Voltage - Monitoring

Feeder voltage used to be monitored by voltage testbanks. Now we rely on the PC-based SynerGEE to perform voltage, fault current, power factor and reliability calculations. Additionally, we rely on customer complaints directed through the phone board.

2. Data Reduction And Analysis

Input data generally needs to be reduced and analyzed in order to put it into a form which will be useful for planning purposes. At the present time this is done both by hand and computer. The most important steps in this process will be described in detail.

a. Asset Management System (AMS)

This system constitutes a major portion of data reduction and analysis. These on-line programs serve as the basic model for our system of distribution feeders. Input data is derived from AMS in a form that allows an analytic model of each distribution feeder to be constructed. This model includes a complete description of each inter-connected feeder line section, connected load, capacitance, and demand loads in the case of primary metering.

b. SynerGEE is an analytical tool that uses data from AMS to create feeder models from inter-connected feeder and lateral sections and automatically calculates section impedances. Actual feeder load and power factor as well as substation impedances are inputted by the Planner.

The analytical function of the program allows files to be generated which are useful in analysis and planning. These files are downloaded to PC's where voltage and fault current analysis can be performed on any feeder. A separate module of the SynerGEE system optimizes the placement of capacitor banks.

b. Feeder Peak Load Analysis

This is a rather straightforward process where the annual feeder peak loads are determined. These peaks practically always occur in the summer. Those feeders with heavy winter peaks usually will have summer peaks of at least equal magnitude except in areas with a large influx of winter residents. Our planning is based primarily on summer peak conditions. Our winter planning method centers on being able to carry the winter peak within the emergency capabilities of the feeder. If winter peaks are a common occurrence in a particular area they can be used in the analysis.

Feeder peak loads are converted from amps to mVA, which is the basis for all planning work. This conversion assumes a secondary equivalent bus voltage of 125V. The thermal or digital ampere meter readings on each feeder provide the basis for determining feeder peak loads. In those cases where these readings are not available, feeder peak loads are estimated based on the loading of the power transformer, connected KVA and customer growth from the previous year.

It is sometimes necessary to adjust the feeder peak should inoperative capacitor banks cause the peak reading to be distorted by abnormally poor power factor. This adjustment is necessary to prevent distortion of load growth trends. The switching of a feeder must be clearly defined since feeder peak load information will otherwise be meaningless. Therefore it is important to have a close working relationship with the Dispatch Office.

Feeder peak load data is used as the basis for several other studies, such as Feeder Load Distribution Analysis, Feeder Load History, and Load Growth Analysis.

b.c. Feeder Load Distribution

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The planning process requires a knowledge of the peak mVA load in each major switchable line section. The PC-based DISTRIBUTION PLANNING SYSTEM performs these calculations. In general, high-density residential areas have the highest coincidence and rural areas have the lowest coincidence. Taking these factors into account allows improvement in estimating kVA demand on a line section basis.

c.d. Annual kW/kVar Study

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This study utilizes the most current model of all feeders based on the summer loading. The worst performing feeders are analyzed with SynerGee which has a capacitor optimization routine. The results of this study culminate in the Capacitor Application Plan which identifies additional capacitor bank requirements for the following year.

C. LOAD PROJECTIONS

Distribution load projections form the basis for developing system expansion plans. Realistic projections depend on a knowledge of those factors which affect distribution load levels. There are a variety of methods available for load forecasting. The choice of method depends on the type of forecast being made. Very often a combination of methods gives the best results. There are several types of projections currently being used in distribution system planning and each will be discussed in detail.

1. Distribution Load Characteristics

Distribution load levels depend on a variety of factors. Knowledge of these factors is the key to good load forecasting. Load variations can be classified as follows:

a. Long term growth trends

b. Seasonal variations - non weather

c. Variations due to weather factors

d. Daily variations

e. Other factors

Each of these factors will be examined in detail.

a. Long Term Growth Trends

Long-term growth trends relate to the total number and type of customers within an area. Factors affecting the long-term trends would include population growth, amount and type of industry in an area, customer usage patterns, degree of A/C and electric heating utilization, etc. Over a period of a few years, this trend may relate closely to population increase, but only if the overall utilization patterns remain constant.

b. Seasonal Variations - Non Weather

There are seasonal variations in distribution loads that are independent of weather. While difficult to identify separately, they are none-the-less significant. Among these variations would be short-term population fluctuations. A significant portion of Florida's population is seasonal. A good measure of this factor is our percent inactive customers. Inactive customers reach a low in March and peak out during the summer months. Other factors affecting the number of inactive customer relate to trends in employment and housing availability.

c. Variations Due to Weather Factors

The most significant factor in annual load variations relates to the weather. The extensive use of electric air conditioning and heating has caused our loads to be very sensitive to temperature and humidity. During summer months, air conditioning may account for more than half of the peak load. Most all of our feeders peak in the summer, generally in late afternoon or early evening. Load projections and planning are usually based on this summer peak.

Winter peaks usually do not exceed the preceding summer peaks in South Florida except when a strong cold front passes through. Winter peaks are of much shorter duration, usually being limited to a few days and occurring between 6 a.m. and 9 a.m. The winter/summer load ratio has been documented at 1.5 times the summer load level in the northern areas and up to 2.0 in the western areas. The western area is higher due to a higher influx of residents during the winter.

d. Daily Variations

Most non-temperature sensitive loads have a distinct 24-hour pattern. The reasons for this are obvious, as they relate to basic daily activities. These patterns are relatively constant throughout the year. They relate to basic commercial activities and residential uses such as cooking, washing, water heating, lighting, etc. This daily variation is lowest from 2 a.m. to 5 a.m. and peaks from 5 p.m. to 8 p.m.

e. Other Variations

These are other factors that will affect distribution load levels. These relate to energy conservation, rate increases, and other economic factors that may cause customers to change their utilization patterns. These factors are often difficult to analyze and predict, but they can have a significant effect on load levels.

f. Summary

The distribution load at a given time is a product of all the factors which have been discussed. It is not always easy, however, to accurately separate and identify these various factors.

2. Load Projection Methods

There are a wide variety of load projection methods available, each with advantages and disadvantages. Some of these methods have been computerized using various PC-based spreadsheet and data base manager software. It is usually necessary to use a combination of methods in order to obtain best results. The more commonly used methods will be discussed in detail.

a. Trend Extrapolation

Perhaps the most used (and abused) form of load projection is extrapolation of a past trend. This usually consists of merely projecting a load history in graphic form. The main advantage of this method is its simplicity. The disadvantage of using this method alone is that no provision is made for changes in present trends. Since load growth trends are cyclic in nature, it is certainly wise to try to identify factors that may influence future trends. In spite of its limitations, trend extrapolation is a good beginning point for the area load projection process. This method works better for overall projection of large areas, and becomes less accurate as the load areas are subdivided.

b. Growth Identification

A method that is quite useful for short-range projections is specific identification of loads to be added to the system. This includes subdivisions being developed, proposed condominiums, apartment buildings and commercial facilities. Identification of such projects can greatly increase the accuracy of short-term projection and is especially useful when dealing with feeder line sections and small geographic areas. These loads are entered in a "New Load File" which is used by the Load Projections Program.

c. Area Growth Potential Analysis

This method is useful for short and long-range projections for specific geographic areas. It requires knowledge of the area's development pattern and such factors as zoning, land use plans and topographic factors. These factors will give some indication of an area's ultimate load potential and roughly how long it will take to reach the ultimate level. Such knowledge fixes realistic limits on growth projections within a given area. This method works best when dealing with smaller areas where development trends have been established.

d. Identification of Change Factors

A useful method by which trend extrapolation can be made more accurate is to identify factors that may change the present trend. This method works best for large geographic areas where trends are available, and a knowledge of change factors exists. These change factors are usually of an economic or environmental nature. Such factors would include "tight money", construction cut-backs, extensive lay-offs, major zoning changes, etc. By applying these factors to past trends, more accurate projections can often be obtained. Since these factors are changed periodically, they may be of limited value when making long range projections.

e. Combining Methods

Most load projections involve a combination of some or all of the methods discussed. This is often an iterative process where trial projections are made by one method and compared with projections by other methods for consistency. Usually this will result in a second cut and perhaps more, until such a time as a projection is obtained which is consistent with all methods.

3. Classification Of Projections

Load projections may be classified both by the area covered and time range. A projection is generally prepared to fill a specific need, and very often several projections will be needed.

a. Projections by Area

Projections may vary in area from the entire company down to a specific section of feeder. Area projections include the following progressively smaller areas:

vii.a)Area

viii.b)Load Area

ix.c)Substation

x.d) Feeder

xi.e)Feeder Section (Switchable)

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b. Projections by Time Range

Time ranges of load projections will vary considerably. Typical ranges are:

Short Range (1-5 years)

Long Range (6-10 years)

4. Projections Now In Use

There are two basic types of load projections now in use. Each fills a specific need and will be discussed in detail. The type of load projection will dictate the projection method or combination of methods to be used.

a. <u>10-Year Long Range Projection</u>

This long-range projection is used primarily for substation site planning and transmission planning and is done annually. An example of the output of this process is shown in Figure 7.

REGION: EAST

10 Year Plan Worksheet For : 2003
Excludes Telecom Loads

Substation	Sub Code	Sum Of Fdr Peaks / Non-Sim Peak	Projections MVA 2002 Deltas % Growth					MVA Growth / Growth Rate	Projections MVA							Current Capacity / Design Capacity	Reg Sim Sub Peak MW 8/1/2002 4 PM	Reg Sim Sub Peak MW 7/9/2003 5 PM
		2003	2003	2004	2005	2006	2007	2003	2008	2009	2010	2011	2012	2013	2014		2002	2003
ACME	40526	101.3	103.4	106.0	112.0	121.6	125.5	3.8	129.3	133.0	136.8	140.6	144.3	148.1	151.9	98.3	87.9	90.3
		90.3	MVA	2.6	6.0	9.6	3.9		3.8	3.8	3.8	3.8	3.8	3.8	3.8	126.5	MW	2.4
		% Increase/Decrease		2.5%	5.7%	8.6%	3.2%	3.0%	3.0%	2.9%	2.8%	2.8%	2.7%	2.6%	2.5%			2.7%
ACREAGE	40676	83.2	96.4	102.4	107.2	112.7	117.9	5.3	118.3	123.4	128.5	133.6	138.7	143.7	148.8	98.3	74.9	79.3
		79.3	MVA	6.0	4.8	5.5	5.2		0.4	5.1	5.1	5.1	5.1	5.1	5.1	126.5	MW	4.4
		% Increase/Decrease		6.2%	4.7%	5.1%	4.6%	4.5%	0.3%	4.3%	4.1%	4.0%	3.8%	3.7%	3.5%			5.9%
ALEXANDER	40856	33.9	37.6	39.8	40.7	49.5	52.2	10.4	55.1	42.4	48.4	54.5	60.6	66.6	72.7	35.0	36.4	28.7
		28.7	MVA	2.2	0.9	8.8	2.7		2.9	-12.7	6.1	6.1	6.1	6.1	6.1	126.5	MW	-7.7
		% Increase/Decrease		5.9%	2.3%	21.6%	5.5%	20.0%	5.6%	-23.1%	14.3%	12.5%	11.1%	10.0%	9.1%			-21.1%
BAYBERRY (FUT)	41173	0.0	0.0	0.0	0.0	15.8	17.8	1.3	19.1	20.5	21.8	23.1	24.5	25.8	27.1	0.0	0.0	0.0
		0.0	MVA	0.0	0.0	15.8	2.0		1.3	1.3	1.3	1.3	1.3	1.3	1.3	123.5	MW	0.0
		% Increase/Decrease		0.0%	0.0%	0.0%	12.7%	7.5%	7.5%	7.0%	6.5%	6.1%	5.8%	5.5%	5.2%			0.0%
BEELINE	40533	76.2	72.4	66.8	70.1	73.4	76.3	0.4	76.7	77.1	77.4	77.8	78.2	78.6	79.0	103.5	64.1	65.5
		65.5	MVA	-5.6	3.3	3.3	2.9		0.4	0.4	0.4	0.4	0.4	0.4	0.4	103.5	MW	1.4
		% Increase/Decrease		-7.7%	4.9%	4.7%	4.0%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%			2.3%
BELVEDERE	40253	53.0	48.8	53.5	54.9	56.9	58.9	1.8	60.7	62.4	64.2	66.0	67.7	69.5	71.3	52.2	42.8	34.9
		44.2	MVA	4.7	1.4	2.0	2.0		1.8	1.8	1.8	1.8	1.8	1.8	1.8	71.8	MW	-7.9
		% Increase/Decrease		9.6%	2.6%	3.6%	3.5%	3.0%	3.0%	2.9%	2.8%	2.8%	2.7%	2.6%	2.5%			-18.6%
BONNETTE	41136	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
		0.0	MVA	0.0	0.0	0.0	0.0		0.0	0.0	0.0	0.0	0.0	0.0	0.0	126.5	MW	0.0
		% Increase/Decrease		0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%			0.0%
CATCHMENT	40976	32.0	25.9	45.6	56.1	64.2	66.4	3.0	69.4	72.4	75.4	78.4	81.3	84.3	87.3	35.0	22.5	37.0
		31.3	MVA	19.7	10.5	8.1	2.2		3.0	3.0	3.0	3.0	3.0	3.0	3.0	126.5	MW	14.5
		% Increase/Decrease		76.1%	23.0%	14.4%	3.4%	4.5%	4.5%	4.3%	4.1%	4.0%	3.8%	3.7%	3.5%			64.7%
CONGRESS	41023	0.0	0.0	0.0	10.1	10.1	10.1	0.5	10.6	11.1	11.6	12.1	12.6	13.1	13.6	0.0	0.0	0.0
		0.0	MVA	0.0	10.1	0.0	0.0		0.5	0.5	0.5	0.5	0.5	0.5	0.5	103.5	MW	0.0
		% Increase/Decrease		0.0%	0.0%	0.0%	0.0%	5.0%	5.0%	4.8%	4.5%	4.3%	4.2%	4.0%	3.8%			0.0%

Figure 7

b. Short-Range Load Forecast

The short-range load forecast is used for detailed project planning and justification. This forecast is by switchable line section, and is totalized by feeder, substation, etc.

This five-year forecast relies heavily on load identification and analysis of area potential. The load projection program is part of the DISTRIBUTION PLANNING SYSTEM. The program adjusts the new loads and other line sections that grew to match an area forecast.

The detailed projections by switchable line section allows alternatives in feeder switching to be examined and evaluated, and new project requirements to be determined.

These short-range forecasts can be produced on computer generated feeder "load maps" in order to facilitate analysis. A sample of such a map is shown in Figure 8.

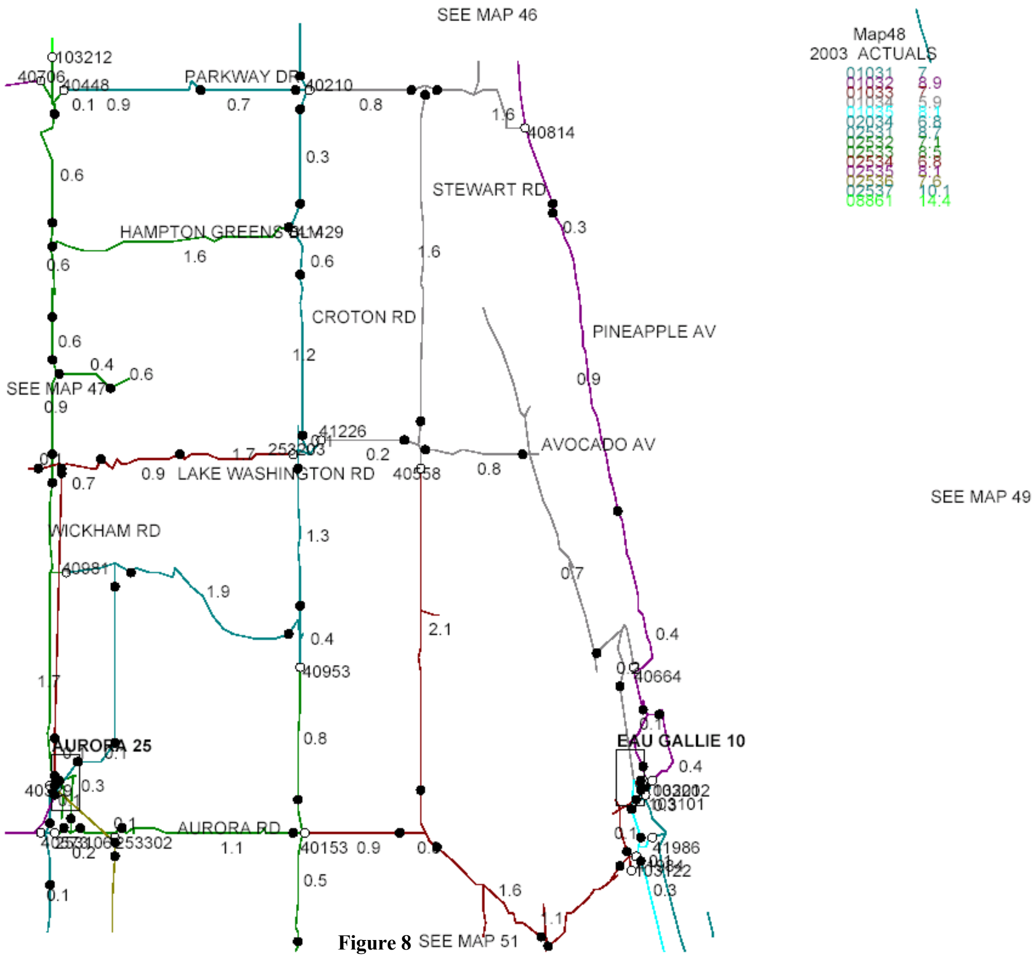


Figure 8

D. PROJECT PLANNING

Load projections provide the basis for distribution system planning. Knowing the present system configuration and the future load growth requirements, the first step in planning is to determine whether the present system is capable of meeting these requirements. Given a progressive load growth, there will be a point in time at which the present system is no longer adequate. The next step, therefore, is to determine the most economical way to increase the system's capabilities to meet these needs. Usually several alternative solutions can be found, and an economic evaluation is necessary. Sometimes the best alternative will be obvious, other times a more detailed analysis will be required. Where alternative plans are developed over a period of several years, an Economic Decision Making (EDM) Analysis should be made to determine the most economical approach.

This planning process will now be discussed in detail on a step by step basis.

1. Planning Load Maps

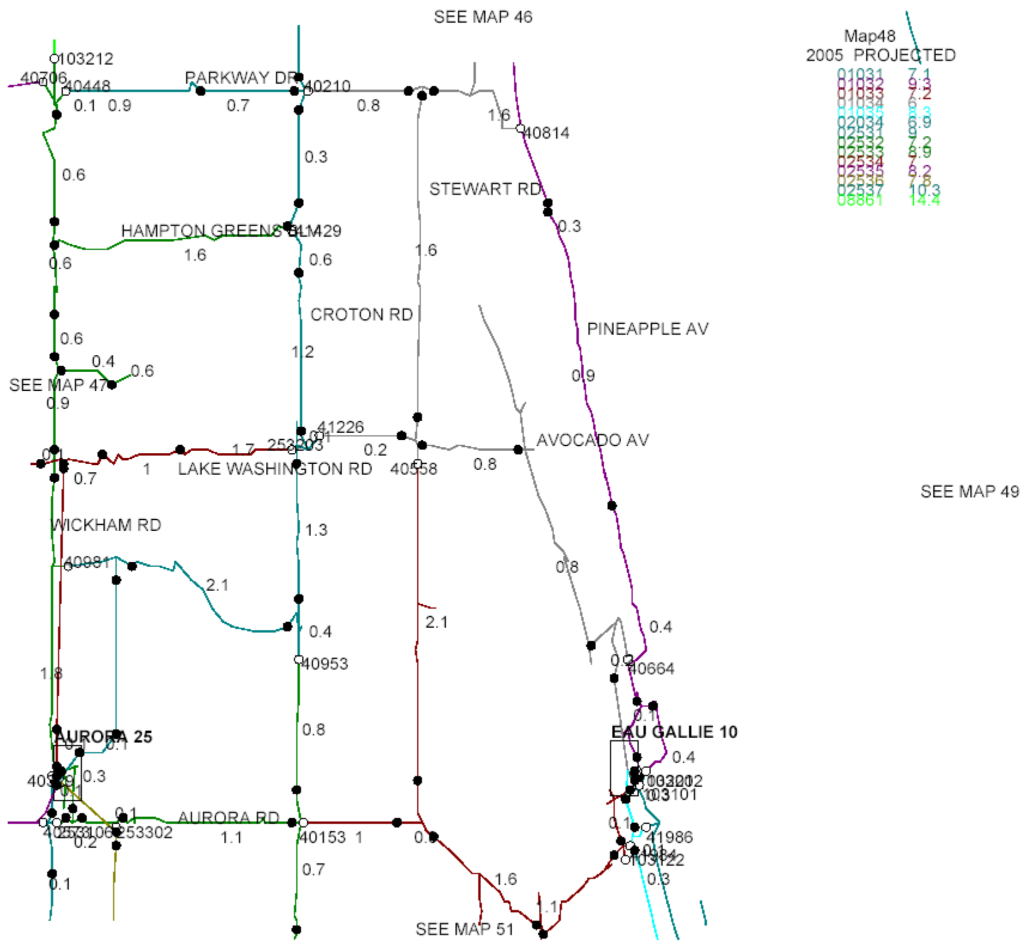
Planning Load Maps are used as a convenient tool to evaluate system capability. A typical planning map is shown in Figure 9. Any one of the three years of history or five years of projected load can be displayed.

The planning map graphically portrays the distribution grid for a Load Area. Load Areas are selected to be more or less independent of other load areas, with few if any distribution ties. Large areas require many planning maps for complete coverage.

The planning map includes substations, the "backbone" feeder sections, switch locations and a tabulation of the load in each line section. The load tabulation can accommodate up to four years of load history or projection. Normal feeder switching alternatives and emergency backup capabilities can be readily evaluated. Proposed projects such as feeder ties, new feeders and new substations can be modeled using the computer. Modeling enables the planning engineer to evaluate the effectiveness of a variety of solutions to a given problem. Since the distribution system is capital intensive, significant time is spent on this aspect of planning the distribution system to increase confidence that the proposed solution is indeed the best way to provide for the area's needs.

2. Contingency Analysis

In order to evaluate the capability of the distribution system to meet a given load level, a contingency analysis is made. Starting with a given feeder switching configuration, each feeder is examined under normal operating conditions to assure that cable, conductor and equipment ratings are not exceeded. If significant overloads exist, then alternatives must be examined. If normal ratings are not exceeded, then the next step is the contingency analysis. The purpose of the contingency analysis is to determine whether loss of a critical line section, or piece of equipment will result in a permanent interruption to a large number of customers until such time as repairs are completed. Our goal is to have sufficient emergency backup capability in the system to avoid such a situation. All of this work is done on the PC using the Feeder Out and Line Section Out programs.


SEE MAP 46
Map48
2005 PROJECTED
PARKWAY DR
STEWART RD
HAMPTON GREENS BLV
CROTON RD
PINEAPPLE AV
SEE MAP 47
AVOCADO AV
LAKE WASHINGTON RD
WICKHAM RD
SEE MAP 49
AURORA 25
EAU GALLIE 10
AURORA RD
SEE MAP 51

a.

Figure 9

b. Typical Contingencies

Typical contingencies that must be taken into account include:

1) Loss of a station transformer - This contingency is usually covered by the second station transformer which may be loaded up to 130% (summer) 150% (winter) under these conditions for the first load cycle. After the first load cycle a mobile tranformer will be available for stations appropriatly equipped and the summer loading on the remaining transformer(s) will be limited to 115% of the nameplate. Stations which have only one transformer must depend on support from adjacent feeders fed from other stations for the first load cycle until the mobile arrives.

2) Loss of Feeder Breaker - This contingency is usually covered by utilizing the inspection breaker. If there is no inspection breaker, the load on the feeder will have to be shifted to adjacent feeders. Such loads must be within the emergency capacity of the relieving feeders.

3) Loss of Feeder Regulator - The feeder regulator can be by-passed in an emergency if the station bus voltage is within reasonable limits. If not, relief must be obtained from adjacent feeders.

4) Loss of Feeder Reactors - Loss of a reactor will generally put the feeder position out of service until repairs can be made. Relief must be obtained from other feeders.

5) Loss of Feeder Pulloff - Loss of the feeder pulloff will take the feeder completely out of service. In cases where the pulloff is underground, the feeder may be out of service for extended periods. Relief must be obtained from adjacent feeders.

6) Loss of Critical Line Sections - The effect of such a loss depends on its location in the feeder grid. Generally, loss of line sections near the substation have the greatest impact, such as those sections with autotransformers. Loss of underground sections are more critical than overhead sections due to the length of repair time. Sometimes a whole feeder may be taken out of service, in other cases only a portion of a feeder may be affected. In either event, relief must be obtained from adjacent feeders.

Since the most serious contingencies involve the loss of an entire feeder, the "Feeder out Analysis" is the basic tool for system evaluation and planning. This PC program systematically takes each feeder out of service and determines which switches need to be opened and closed to pick up the load. A typical feeder outage analysis output is shown in Figure 10.

FLORIDA POWER & LIGHT DISTRIBUTION FEEDER OUTAGE PROGRAM

Option 5: Overloaded Feeder Details

Load Area: NA
Date : 09-20-2004

Load Year : 04
Solution Limit : 1

File : FONASU04.530
Time: 13:50:43

Cat Type	Feeder Out	Normal Load	Open Switch	Open Switch	A	Adjacent Feeder 1	C	Close Switch	Normal Load	Load Added	Total Load	Emergency Capacity	Percent Loaded	Adjacent Feeder 2	Close Switch	Normal Load	Load Added	Total Load	Emergency Capacity	Percent Loaded	Adjacent Feeder 3	Close Switch	Normal Load	Load Added	Total Load	Emergency Capacity	Percent Loaded	AVG PCT	OPT FAC	MVA Def
5	1232	11.4	12171	123239	A	1238	C	123157	7.5	4.6	12.1	11.5	106	1237	123232	8.0	4.6	12.6	11.5	110	1239	123227	10.3	2.2	12.5	11.5	109	108	8.7	2.7
4	1233	8.4		123239	A	1238	C	123157	7.5	4.6	12.1	11.5	105	1237	123322	8.0	3.8	11.8	11.5	102								104	2.6	0.9
5	1236	9.0	123215	123339	A	1234	C	123231	9.8	3.3	13.1	11.5	114	1239	11686	10.3	2.7	13.0	11.5	113	3564	123444	19.3	3	22.3	19.8	113	113	3.3	5.6
5	1239	10.3	123339	11688	A	1232	C	10810	11.4	1.7	13.1	11.5	114	1233	11730	8.4	5.3	13.7	11.5	119	1234	123231	9.8	3.3	13.1	11.5	114	116	10.4	5.4
5	4061	15.7	40149	40081	A	3561	C	10611	9.4	6.3	15.7	19.8	79	3569	13275	15.8	6.0	21.8	19.8	110	4062	40607	17.5	3.4	20.9	19.8	106	98	61.6	3.1
5	4062	17.5	41074	40878	A	3569	C	13275	15.8	7.0	22.8	19.8	115	4061	40607	15.7	4.1	19.8	19.8	100	3567	40874	16.3	6.4	22.7	19.8	115	110	30.3	5.9
5	4063	20.8	61290	41074	A	3567	C	40874	16.3	6.4	22.7	19.8	115	4062	40562	17.5	4.0	21.5	19.8	109	4061	41018	15.7	10.4	26.1	19.8	132	119	46.5	10.9
5	4962	18.0	A13280	40431	A	3566	C	A13258	17.5	4.9	22.4	19.8	113	4963	13286	16.8	6.2	23.0	19.8	116	4966	13281	14.1	6.9	21	19.8	106	112	20.2	7.0
3	4963	16.8	40114	40431		3567		353109	16.3	4.9	21.2	19.8	107	4962	13286	18.0	3.7	21.7	19.8	109	4967	A13256	13.3	8.2	21.5	19.8	108	108	5.0	5.0
5	4964	15.4	40852	13341	A	6662	C	40222	15.7	2.3	18.0	19.8	91	6663	A14039	17.8	4.3	22.1	19.8	111	4966	40429	14.1	8.8	22.9	19.8	116	106	49.4	5.4
3	4966	14.1	40250	12150		4962		40468	18.0	3.4	21.4	19.8	108	4964	40429	15.4	5.4	20.8	19.8	105	6662	A13253	15.7	5.3	21	19.8	106	106	6.1	3.8
4	4967	13.3		13279	A	6662	C	A14037	15.7	5.5	21.2	19.8	107	4966	40109	14.1	7.8	21.9	19.8	110								109	3.5	3.5
3	6662	15.7	313105	12156		3566		A14038	17.5	1.8	19.3	19.8	97	4966	A14037	14.1	5.0	19.1	19.8	96	6661	11247	11.7	8.9	20.6	19.8	104	99	15.1	0.8
5	6663	17.8	A14053	10198	A	6661	C	A14032	11.7	5.4	17.1	19.8	86	6665	40482	14.9	6.9	21.8	19.8	110	6662	11991	15.7	5.5	21.2	19.8	107	101	47.4	3.4
5	6665	14.9	40599	12449	A	3133	C	12751	6.3	1.0	7.3	11.5	63	6661	A14032	11.7	8.6	20.3	19.8	103	4363	A14049	14.8	5.3	20.1	19.8	102	89	78.3	0.8
3	6763	27.6	13855	A14187		4367		13997	13.4	10.5	23.9	19.8	121	4964	10413	15.4	7.9	23.3	19.8	118	6766	13780	14.6	9.2	23.8	19.8	120	120	6.1	11.6
5	6766	14.6	A14183	41150	A	4364	C	A14182	11.2	3.6	14.8	19.8	75	6762	A14184	15.5	4.5	20.0	19.8	101	4367	10923	13.4	6.5	19.9	19.8	101	92	52.5	0.3
5	7062	26.3	11550	13677	A	7063	C	13678	9.7	13.7	23.4	19.8	118	7061	40654	17.5	5.7	23.2	19.8	117	3968	12082	14.4	6.9	21.3	19.8	107	114	21.2	8.5
5	1231	9.9	123144	11510	A	1235	C	123522	9.2	2.1	11.3	11.5	98	1238	40080	7.5	4.0	11.5	11.5	100	3133	123141	6.3	3.8	10.1	11.5	88		95	24.3
4	1234	9.8		123313	A	3562	C	A14110	13.0	4.0	17.0	19.8	86	3568	10867	10.1	5.8	15.9	19.8	80									83	5.6
5	1235	9.2	123503	123225	A	1238	C	123521	7.5	1.2	8.7	11.5	76	1237	123702	8.0	3.1	11.1	11.5	97	3133	123504	6.3	4.9	11.2	11.5	97		90	43.5
5	1237	8.0	123519	11510	A	1235	C	123522	9.2	2.1	11.3	11.5	98	1238	123157	7.5	3.8	11.3	11.5	98	1233	123322	8.4	2.1	10.5	11.5	91		96	13.9
3	1238	7.5	123103	11510		1231		40080	9.9	1.1	11.0	11.5	96	1235	123522	9.2	2.1	11.3	11.5	98	3133	123121	6.3	4.3	10.6	11.5	92		95	12.2
2	2161	14.1	40008			2163		213104	10.5	8.0	18.5	19.8	93	2168	40552	10.1	6.1	16.2	19.8	82									88	11.6
3	2162	19.1	213202	14617		2167		40781	16.5	2.8	19.3	19.8	97	2165	213208	5.0	14.8	19.8	19.8	100	7061	11685	17.5	1.5	19.0	19.8	96		98	8.1
2	2163	10.5	14020			2161		213104	14.1	0.8	14.9	19.8	75	6768	40794	9.7	9.7	19.4	19.8	98									87	22.7
5	2164	14.7	40278	11381	A	2168	C	40552	10.1	4.9	15.0	19.8	76	2161	10939	14.1	4.9	19.0	19.8	96	4370	A14159	14.2	4.9	19.1	19.8	97		89	41.4
1	2165	5.0				7063		40967	9.7	5.0	14.7	19.8	74																	
2	2166	19.4	A40666			2163		40674	10.5	5.0	15.5	19.8	78	2165	41009	5.0	14.4	19.4	19.8	98									88	19.7
3	2167	16.5	12142	A14161		2163		40965	10.5	9.2	19.7	19.8	99	2164	A14163	14.7	2.7	17.4	19.8	88	4364	A13987	11.2	4.6	15.8	19.8	80		89	39.4
1	2168	10.1				3964		41137	7.8	10.1	17.9	18.3	98																	
2	3131	8.6	40127			3133		40471	6.3	4.9	11.2	11.5	97	6665	11397	14.9	3.7	18.6	19.8	94									96	3.5
5	3132	9.9	12965	123142	A	1231	C	123141	9.9	1.6	11.5	11.5	100	3133	40180	6.3	5.1	11.4	11.5	99	3134	313203	7.6	3.2	10.8	11.5	94		98	12.2
1	3133	6.3				6661		12751	11.7	6.3	18.0	19.8	91																	
2	3134	7.6	313204			3133		313213	6.3	5.0	11.3	11.5	98	3136	313404	6.7	2.6	9.3	11.5	81									90	17.4
1	3135	7.9				4369		40563	10.9	7.9	18.8	19.8	95																	
4	3136	6.7		313204	A	3133	C	313213	6.3	5.0	11.3	11.5	98	3134	313404	7.6	1.7	9.3	11.5	81									90	17.4
4	3137	6.6		313502	A	4369	C	40563	10.9	7.4	18.3	19.8	92	3135	40495	7.9	-0.8	7.1	11.5	62									77	30.7
2	3138	10.7	10908			3133		41065	6.3	2.1	8.4	11.5	73	4369	41126	10.9	8.6	19.5	19.8	98									86	25.4
2	3561	9.4	13300			3562		353202	13.0	3.4	16.4	19.8	83	3565	10444	13.5	6.0	19.5	19.8	98									91	15.7
2	3562	13.0	A14100			3561		353202	9.4	4.2	13.6	19.8	69	3568	A14121	10.1	8.8	18.9	19.8	95									82	26.8

Figure 10

1

c. Evaluation of Alternatives

When an overload or lack of sufficient backup capacity has been identified in the feeder out analysis, the next step is to examine alternatives which eliminate the problem. Such alternatives may be a change in switching, reconductoring a line section, adding a feeder tie, adding a feeder, or even adding a substation. The alternatives can be modeled in the distribution planning system to determine the effectiveness of the proposed solution. The simplest and most economical alternative is usually chosen. Also the cost of any alternative must be weighed against the contingency which it is to prevent. Sometimes it is preferable to accept a degree of risk.

It is not uncommon to encounter alternative approaches which span a period of several years. Such a case may be whether to build a new substation or to develop express underground feeders out of an existing station. Since expenditures will be over a period of several years, some means is needed to realistically compare costs. A convenient and accepted procedure for doing this is the EDM Analysis. This analysis allows us to relate project costs back to an annual revenue requirement. There is a company course on this method because it can get complicated. A PC program has been written in Excel to handle the computations.

One of the more frequently encountered problems in distribution system planning is when to build new substations. In general it will be found more economical to develop additional feeders out of existing stations, even when express and parallel feeder runs are required. There will be a point in time, however, when a new substation will be justifiable for one of the following reasons:

7)1) Adjacent existing stations are not capable of further expansion.

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8)2) All possible additional feeder routes into an area are exhausted.

9)3) Additional feeder routes from existing stations for the period studied are so costly that an EDM Analysis will favor construction of a new station.

10)4) In rural areas fed by a long radial run from another station which has reached its ultimate capacity. This usually will occur only after conversion to 23 kV.

11)5) By management decision in order to avoid an adverse public reaction at a future date.

3. Five-Year Plan

The Five-Year Plan is a summary of the projected loads and the system configuration that has been proposed to meet these loads. This proposed system configuration is a result of the contingency analysis and evaluation of alternatives. Basically, the Five-Year Plan shows the loads we expect to serve and how we plan to serve them. An example of this plan is shown in Figure 11.

The plan is usually made on a Load Area basis. It shows proposed feeder and substation loading for five years. Also included for reference are the station transformer capacities and feeder ratings. A summary is provided which totals load for the area, and gives statistics such as annual % load growth, mVA per station and mVA per feeder. This plan is quite useful in giving an overall picture of the distribution system planning for a given area, and its effectiveness.

Distribution Reliability and Planning
FIVE YEAR PLAN FOR NON-SPECIALTY SUBSTATIONS

Region NORTH — **Base Year:** 2003

Region	Manager Area	Planning Area	District:	Substation	Buss Voltage:	In Service:	Speciality	Install Date:
NORTH	BV	BV	22	HIELD	23 KV	Yes	No	6/1/1994

Mgr Area	Plan Area	Feeder	In Service	Install Date	Spec.	Ratings: Reg	Ratings: Normal	Ratings: Emerg.	Ratings: Ph. Relay	History MVA: 1998	1999	2000	2001	2002	Base: 2003	Projected MVA: 2004	2005	2006	2007	2008
BV	BV	208161	Yes	6/1/1995	No	0.0	19.8 P	19.8 P	19.8	21.0	17.9	15.9	15.7	15.2	14.1	14.1	14.1	14.1	14.4	9.8
BV	BV	208162	Yes	6/1/1995	No	0.0	19.8 P	19.8 P	19.8	7.4	7.3	6.9	6.7	6.6	6.6	6.6	6.6	6.7	6.8	6.9
BV	BV	208163	Yes	6/1/1995	No	0.0	19.8 P	19.8 P	19.8	14.2	16.4	16.8	14.0	14.4	14.3	14.4	14.4	14.4	15.1	15.4
BV	BV	208164	Yes	11/26/1999	No	0.0	19.8 P	19.8 P	19.8	0.0	0.0	15.9	12.9	13.2	13.4	13.7	16.5	17.0	17.7	11.1
BV	BV	208165	No	5/15/2008	No	0.0	19.8 P	19.8 P	19.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	14.6

Manager Area BV

	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008
Feeder Totals	42.6	41.6	55.5	49.3	49.4	48.4	48.8	51.6	52.2	54.0	57.8
Feeder Count	3	3	4	4	4	4	4	4	4	4	5
Feeder Normal Capacity	65.4	65.4	87.2	87.2	87.4	79.6	79.6	79.2	79.2	79.2	99.0
Feeder Normal Utilization	65.1%	63.6%	63.6%	56.5%	56.5%	60.8%	61.3%	65.2%	65.9%	68.2%	58.4%
Feeder Emergency Utilization	64.5%	63.0%	63.1%	56.0%	56.1%	60.8%	61.3%	65.2%	65.9%	68.2%	58.4%
Substation Nameplate MVA	55.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0
Substation Regional Simultaneous Peak	29.8	31.0	35.1	41.0	42.9	43.2	43.4	45.9	46.5	48.2	51.5
Substation Regional Simultaneous Peak Utilization	54.2%	28.2%	31.9%	37.3%	39.0%	39.2%	39.5%	41.8%	42.2%	43.8%	46.9%
Substation Coincidence Factor	0.70	0.75	0.63	0.83	0.87	0.89	0.89	0.89	0.89	0.89	0.89

Region	Manager Area	Planning Area	District:	Substation	Buss Voltage:	In Service:	Speciality	Install Date:
NORTH	BV	BV	22	HOLLAND PARK	13 KV	Yes	No	4/1/1968

Mgr Area	Plan Area	Feeder	In Service	Install Date	Spec.	Ratings: Reg	Ratings: Normal	Ratings: Emerg.	Ratings: Ph. Relay	History MVA: 1998	1999	2000	2001	2002	Base: 2003	Projected MVA: 2004	2005	2006	2007	2008
BV	BV	202631	Yes	4/1/1968	No	8.6	11.5 P	11.5 P	11.5	8.5	8.9	8.8	9.1	8.8	8.0	8.1	8.2	8.3	8.4	8.5
BV	BV	202632	Yes	10/15/1972	No	11.1	11.3 C	11.5 P	11.5	10.2	10.2	8.4	7.6	7.6	6.0	6.2	6.2	6.3	6.3	6.3
BV	BV	202633	Yes	5/12/1986	No	11.1	11.5 P	11.5 P	11.5	10.5	11.2	6.5	5.5	5.8	5.2	5.3	5.3	5.5	5.7	5.8

Manager Area BV

	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008
Feeder Totals	29.2	30.3	23.7	22.2	22.2	19.2	19.6	19.7	20.1	20.4	20.6
Feeder Count	3	3	3	3	3	3	3	3	3	3	3
Feeder Normal Capacity	36.6	36.6	36.6	36.6	36.6	33.7	33.7	34.3	34.3	34.3	34.3
Feeder Normal Utilization	79.8%	82.8%	64.8%	60.7%	60.7%	57.0%	58.2%	57.4%	58.6%	59.5%	60.1%
Feeder Emergency Utilization	76.6%	79.5%	62.2%	58.3%	58.3%	55.7%	56.8%	57.1%	58.3%	59.1%	59.7%
Substation Nameplate MVA	28.0	53.0	53.0	53.0	53.0	53.0	53.0	53.0	53.0	53.0	53.0
Substation Regional Simultaneous Peak	23.0	25.0	18.7	18.0	17.8	17.2	17.7	17.7	18.1	18.3	18.6
Substation Regional Simultaneous Peak Utilization	82.1%	47.2%	35.3%	34.0%	33.6%	32.5%	33.4%	33.4%	34.2%	34.6%	35.1%
Substation Coincidence Factor	0.79	0.83	0.79	0.81	0.80	0.90	0.90	0.90	0.90	0.90	0.90

Figure 11

4. Substation Site Planning

Substation site planning is of necessity long range. Sites must often be purchased well in advance of their in service date in order to assure availability and reasonable price.

The need for new substations is formulated on the basis of a 10-year long-range load forecast. Starting with an overall area forecast, this is broken down by substation. This is done on the basis of present growth trends and long range growth potential. Substation needs are then determined, being timed to correspond with load growth requirements. The resulting long-range substation site plan pinpoints the general location and service required date for future substations.

As the proposed purchase date of a substation site approaches, then a more detailed determination of location and purchase schedules must be made. The following criteria are in general use for location and scheduling of site purchases.

a. Criteria for Locating Substation Sites

The criteria for locating substation sites relates both to system requirements and real estate considerations.

1)6) The station should, at the time of installation, be located in a "load center" and reasonably equidistant from other stations. This will minimize feeder voltage drop and line losses.

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2)7) The station should be located close to existing transmission facilities where feasible. In areas where transmission facilities must be installed, the location should be such that transmission routes are readily available.

3)8) A location which lends itself to getting feeders out in all directions is desirable. This will minimize costly express and parallel pulloffs.

4)9) The station should be located such that the aesthetic impact on the area is minimal. Locations which would require expensive decorative walls should be avoided when possible.

5)10) Property should be available at reasonable price.

6)11) Property should require a minimum of site preparations. Areas requiring extensive fill work should be avoided.

7)12) Proper zoning should be attainable.

b. Criteria for Scheduling Substation Site Purchase

Substation site purchase should be scheduled only when the purchase can be justified by one of the following criteria.

1)13) Sites should be purchased a minimum of five years prior to the in-service date.

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2)14) Sites may be purchased further in advance where the property is subject to no longer being available.

3)15) Sites may be purchased further in advance where the current price is extremely favorable.

4)16) Sites may be purchased further in advance where land values are appreciating faster than the current rate of interest. In such cases it is cheaper to purchase than to wait and pay a much higher price.

5)17) Sites may be purchased further in advance in those situations where there is a need to put adjacent property owners on notice of our intentions well in advance of construction. This would usually be in an area where future objection to our use of the property is anticipated. This is strictly a management decision.

E. SYSTEM EXPANSION BUDGETING

The end result of the planning process is the System Expansion Budget which is entirely on-line in a Lotus Notes data base accessible by everyone. The purpose of the budget is to provide review, authorization and financial commitment for construction projects necessary to accommodate system growth.

Requests are entered online along with justification for a project. Known as a "Purpose and Necessity", this justification, together with project cost data and supporting materials make up the "Request for Budgeting" which is reviewed and approved by the Manager of Distribution Reliability Planning. Area Managers also have the ability to concur with recommendations by signing off on the project online.

1. The "Purpose And Necessity"

No planning process is complete unless its conclusions are clearly documented. The Purpose and Necessity is actually a concise summary of the logic used in the planning process. It answers the basic questions:

a) What is being proposed?
b) What will it accomplish?
c) Why is it necessary?
d) When is it required?
e) Why is it being done this way?
f) Why must it be done now?
g) What will happen if it is not done?

The Purpose and Necessity (P&N) should be clear and concise, and logically develop the justification for the project under consideration. Stick to the facts and develop an iron-clad case. Avoid generalizations, vague assumptions and "shot gun" techniques. The text should rarely exceed one typewritten page. Marked-up Visio type drawings of primary maps, load tables, economic data and documented new load should be attached.

The text of a P & N usually follows the following pattern:

a)h) Description of the Project
b)i) The Need - usually pointing out the substandard condition which needs correction
c)j) How this project will solve the problem
d)k) What will happen if this project is not worked now
e)l) What alternatives exist, and why they were not chosen; if due to cost, state cost of alternative

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Supporting data will generally be needed to supplement the text. Do not include data that does not directly relate to your proof. Supporting data will usually include some, but not likely all of the following:

a)m)Marked Primary & Feeder Maps
b)n) Load Tabulation or Projection
c)o) Voltage Profile
d)p) Fault Current Analysis
e)q) Reliability Analysis
f)r) Feeder Out Analysis
g)s) Motor Starting Analysis
h)t) Economic Analysis
i)u) Documented Load Addition, such as apartment or housing project, if known.

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An example of a typical P & N with supporting data and cost summary is included as Figures 12-15.

FPL

Request For Budgeting Expansion Plan Project

Description

Description: Panacea Sub 8861, 8862

Project Funding:	Expansion	Revision Date:	09/20/2004 10:55:53 AM
Budget Book Year:	2005	Urban / Suburban:	Suburban
Category:	Substation	Region:	West
Project Year:	2005	Manager Area:	TB
Activity Code:	072808	Service Center Area:	TBO
Planning Load Area:	TB	Power Delivery Required:	● Yes ○ No
Planning Required Date:	06/01/2005	Priority Grouping:	Normal
Negotiated In Service Date:		Priority Number:	10
RTS Feeder Number:		Project Status:	Proposed
Substation Name:	Panacea	Risk Score:	1
Growth Type:	NG- New Growth	Criteria Score:	113,918
Visibility Score:		Total Score:	113,918
Intensity Score:			

Reliability Planner: Richard Becker Phone: (941) 331-4181 Mail Code: DPR/SS2

Remarks:

Field Checked? ○ Yes ● No

Field Comments:

Click on me for glossary of terms

Install & Removal Information

	Number Installed	MVA Capacity Increase
Substations:	1	55
Power Transformers:	1	0
Feeders:	2	39.6

Please select the sizes for data input:

Conductor Sizes	Install	# of Phases	Remove	# of Phases
UG - 1000AU	1,200	3	0	
OH - 1/0A	0		47,600	1
OH - 568A	49,000	3	0	

Auto Transformer	Install	Size	Remove	Size

Other:

Distribution Cost Information

DISTRIBUTION DUCT/BORE SUMMARY COST:

Distribution	Capital	O & M	CNST Manhours
Duct Bank:	$0	$0	0
Directional Bores:	$39,600	$0	126

Figure 12

DISTRIBUTION SUMMARY FROM PROJECT COST:

Distribution	Capital	O & M	Net Plant	CNST Manhours
Overhead:	$1,164,100	$239,932	$0	9,704
Underground:	$96,000	$3,300	$0	342
Total:	$1,260,100	$243,232	$0	10,046

DISTRIBUTION MANUAL ADJUSTMENTS:

Distribution	Capital	O & M	Net Plant	CNST Manhours
Overhead:	$0	$0	$0	0
Underground:	$0	$0	$0	0
Total:	$0	$0	$0	0

DISTRIBUTION TOTALS AFTER MANUAL ADJUSTMENTS:

Distribution	Capital	O & M	Net Plant	CNST Manhours
Overhead:	$1,164,100	$239,932	$0	9,704
Underground:	$96,000	$3,300	$0	342
Total:	$1,260,100	$243,232	$0	10,046

SUBSTATION & TRANSMISSION MANUAL ENTRY:

Substation & Transmission	Capital	O & M	Reserve	CNST Manhours
Substation:	$996,698	$9,924	$793,600	6,248
Transmission:	$100,000	$0	$0	0
Total:	$1,096,698	$9,924	$793,600	6,248

POWER SYSTEMS GRAND TOTAL:

Power Systems	Capital	O & M	PLANT	RESERVE	CNST Manhours
Total	$2,356,798	$253,156	$0	$793,600	16,294

Real Estate:

Real Estate	Capital Land Cost Range
Low End:	$1
High End:	$9

Purpose & Necessity Information

Panacea Substation - 230/23KV
North Port, Sarasota County, FL
Initially: 1-55 Mva TX w/ 35Mva Mobile & 2-23 KV Feeders
Ultimate: 2-55 Mva Tx w/ Mobile & 6-23KV Feeders

The purpose of this project is to build Panacea Substation. This Project is needed to serve the fast growing Toledo Blade area. Growth in the area includes: a new large single family subdivision (Panacea / Wood Bridge, 500 Homes), continued growth with platted single family homes around the substation location (approximately 200 homes per year), a new Hospital at the corner of Toledo Blade Blvd and Price Blvd, and the Commercial Park where the substation is located.

The Area is currently being served from Franklin 6463 (17.5 MVA) a large 23KV feeder with total length of 25.9 Miles and 5,119 customers. The adjacent Feeders in the Area are Murdock 2065 (14.4 MVA, 8.5 Mi) and Cocoplum 6365 (11.5 MVA, 20.1 Mi). None of the three feeders in the area have sufficient Capacity to pick up load in the event of an outage, due to the loading, insufficient feeder ties and lack of grid.

The growth rate in this area is 6% and the long range plan for this section of Toledo Blade is indicating the need for a substation with the lack of grid and distance between existing substations. Bringing additional feeders from existing substations is not a viable

Figure 13

solution because the length of the feeders will be greater then the Model Feeder criteria.

Alternatives to constructing the Panacea Sub station in 2005 would involve building two feeders out of the Franklin Sub (6465 & 6466) and one additional feeder out of the Cocoplum Sub (2065). Along with the additional feeders, a mobile connection at both of the substation would be needed, in the event of losing a transformer. By constructing the 3 feeders and adding the mobiles, we would still have to construct the Panacea Sub in 2006 to meet the winter loading and continuing load growth North of the Panacea Substation.

By constructing the Panacea substation in 2005, it would free-up the Franklin feeder in the future to serve the new Murdock Village, currently in design and permitting.

The most cost efficient solution would be to construct the panacea sub with two feeders in 2005, this would also fit into the long range plan for this area.

Feeders being effected:
Cocoplum 3264
Cocoplum 6265
Murdock 2065
Franklin 6463

Other Information & Attachments

Attachments (Load Studies, Economic Analysis, Maps):

LT05_PANACEA.xl EXP05_GC_FM_PANACEA_8861_8862 Panacea_EDM.xls

LID:	5,539	**Normal Utilization %:**	72%
CID:	1,216,881	**Emergency Utilization %:**	76%
CI Savings:	439	**Operating Capacity Added:**	18,365.0
Before Proj - FDR High Cust Count:	1	**After Proj - FDR High Cust Count:**	9

Feeder	**MVA Deficit** Single	Total	**Percent Overload**	**Device**
Normal:	4.4	4.4	127%	C- Cable
Throwover:				
Contingency:	1.1	4.2	106%	P- Phase

Power Transformer	**MVA Deficit** Single	Total	**Percent Overload** (From nameplate)
Normal:			
Contingency:			

Recommended For Budgeting - Area Manager

Area Manager Sign-off:

Recommended for Budgeting - Reliability Planning Manager

Reliability Planning Manager Sign-off:

Figure 14

Figure 15

SUMMER LOAD TABLE Feeder: 506463

Base Year: 2003

Without Project (Case / TB / SO05)

Substation	Feeder	Ratings Normal	Ratings Emerg	MVA Load Normal	MVA Load Emerg	Normal Overload MVA	Normal Overload %	Emerg Overload MVA	Emerg Overload %	Customer	LID	CID
FRANKLIN	506463	16.4 C		20.8		4.4	127%			4,083	5,539	1,216,881
MURDOCK	502064	19.8 P	19.8 P	16.2	16.2					2,229	329	12,505
MURDOCK	502065	19.6 C	19.8 P	13.2	13.2					3,407	821	202,705
MURDOCK	502067	19.8 P	19.8 P	9.0	19.6					1,627	762	145,862
COCOPLUM	503262	19.8 P	19.8 P	16.4	16.4					3,727	1,410	314,330
COCOPLUM	503263	18.2 C	19.8 P	8.1	8.1					2,620	450	143,023
COCOPLUM	503264	19.8 P	19.8 P	17.4	17.4					4,584	185	59,458
COCOPLUM	503265	19.8 P	19.8 P	7.3	7.3					2,280	3,276	925,726
DEEPCREEK	506361	19.8 P	19.8 P	17.6	17.6					3,654	1,284	266,109
FRANKLIN	506461	16.4 C	18.6 C	13.5	13.5					869	2,396	363,071
FRANKLIN	506464	19.7 C	19.8 P	10.7	20.9			1.1	106%	2,317	513	112,288
PANACEA	508861											
PANACEA	508862											
	Totals	209.1	196.8	150.2	150.2	4.4		1.1		31,397	16,965	3,761,958
	Utilization			72%	76%				Avg	2,854		

Projected MVA for Summer of 2005 — With Project (Case / TB / S5AA)

Substation	Feeder	Ratings Normal	Ratings Emerg	MVA Load Normal	MVA Load Emerg	Normal Overload MVA	Normal Overload %	Emerg Overload MVA	Emerg Overload %	Customer	LID	CID
FRANKLIN	506463	16.4 C		9.0						1,834	5,539	1,216,881
MURDOCK	502064	19.8 P	19.8 P	16.5	16.5					1,781	329	12,505
MURDOCK	502065	19.6 C	19.8 P	13.5	18.6					3,702	821	202,705
MURDOCK	502067	19.8 P	19.8 P	9.0	9.0					1,627	762	145,862
COCOPLUM	503262	19.8 P	19.8 P	10.6	10.6					2,423	1,410	314,330
COCOPLUM	503263	18.2 C	19.8 P	9.1	9.1					2,833	450	143,023
COCOPLUM	503264	19.8 P	19.8 P	10.1	10.1					2,595	185	59,458
COCOPLUM	503265	19.8 P	19.8 P	8.9	8.9					2,691	3,276	925,726
DEEPCREEK	506361	19.8 P	19.8 P	15.2	15.2					3,099	1,284	266,109
FRANKLIN	506461	16.4 C	18.6 C	13.8	17.7					1,505	2,396	363,071
FRANKLIN	506464	19.7 C	19.8 P	10.7	10.7					2,317		
PANACEA	508861	19.8 P	19.8 P	13.5	13.5					2,695		
PANACEA	508862	19.8 P	19.8 P	10.3	10.3					2,295		
	Totals	248.7	236.4	150.2	150.2					31,397	16,452	3,649,670
	Utilization			60%	64%				Avg	2,415		

Contingency MVA Deficit		Normal MVA Deficit		CI Avoidance		Improvement	
Single Situtation	1.1	Single Situation	4.4	Single Situaton	18,365	LID	112,288
Total Situations	4.2	Total Situations	4.4	Total Situation		CID	

Area MVA Loads

Year	2000	2001	2002	2003	2004	2005	2006	2007	2008
MVA	119.3	125.9	131.3	143.8	146.4	150.2	155.5	158.8	162.5
Growth %		5.5%	4.3%	9.5%	1.8%	2.6%	3.5%	2.1%	2.3%

Notes:

Note: Contingency overload 6361 - 1.0, 6362 - 0.1, 6364 - 0.9, 6464 - 1.1
Winter OverLoad 6463 - 6.4, 3262 - 2.8, 3242 - 4.4, 6361 - 1.9
Customer Count Fdr6463 = 4,083 -> 1,834, fdr 3264 = 4,584 -> 2,595, Fdr 6361 = 3,654 -> 3,099

Component Table MVA Overloads

	Substation	Feeder	Breaker MVA	Breaker %	Regulator MVA	Regulator %	Pickup MVA	Pickup %	Cable MVA	Cable %	Wire MVA	Wire %	Auto MVA	Auto %
NORMAL	FRANKLIN	506463							4.4	127%				
EMERGENCY	MURDOCK	502067			1.3	107%								
EMERGENCY	FRANKLIN	506464					1.1	106%						

Form: DPMLoadTable.xls Revised: 5/25/2004

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2.1.7 DISTRIBUTION SYSTEM RELIABILITY

GENERAL

Distribution reliability activities estimate, control and manage the probability of failure of equipment, systems, and processes to satisfy customer needs for available electrical service within cost and technical constraints. To improve the reliability of existing systems and predict the performance of proposed systems, reliability personnel identify reliability needs, assess historical outages, model alternative network configurations and implement appropriate maintenance levels. Currently at FPL, a Momentary is defined as an outage lasting less than 1 minute. An Interruption is an outage of 1 minute or more.

A. RELIABILITY INDICATORS AND TARGETS

Definitions:

CI - Customers Interrupted

CMI - Customer Minutes Interrupted

CS - Customers Served

CM - Customer Momentaries (The number of customers affected by a momentary)

CME - Customer Momentary Events (The number of customers affected by a momentary event)

MI – Minutes of Interruption (The number of minutes until the last customer is restored)

N – Number of Interruptions

SAIDI	$SAIFI \times CAIDI$ (frequency * duration)	System Average Interruption Duration Index. The number of minutes the typical FPL customer will be without power. Usually calculated for 12MOE, YTD, and individual month. (Service Unavailability or SU)
CAIDI	$\frac{\sum CMI}{\sum CI}$	Customer Average Interruption Duration Index. The average number of minutes power will be out each time an interruption occurs. (Duration)
SAIFI	$\frac{\sum CI}{CS}$	System Average Interruption Frequency Index. The number of times the typical FPL customer will experience an interruption. (Frequency)
MAIFI	$\frac{\sum CM}{CS}$	Momentary Average Interruption Frequency Index. Momentaries per Feeder indicator that gives weight to the number of customers on the feeder. (for FPL internal use)
MAIFIe	$\frac{\sum CME}{CS}$	Momentary Event Average Interruption Frequency Index. Some Events may have more than one Momentary associated with them if the Feeder relays several times. Note: This indicator (vs MAIFI) is reported to the FPSC.
L bar	$\frac{\sum MI}{N}$	The average number of minutes from the time power is lost until power is restored to all customers.
# Cust > 5		The number of customers experiencing over 5 interruptions within a 12 month period.

In reporting reliability performance to the FPSC, certain events such as hurricanes and tornados are excluded from the data.

Two sources are used to set the reliability goals for the FPL distribution system. Ongoing *customer surveys* measure reliability needs and *benchmarking studies* assess the performance of other electric utilities.

Surveys of FPL customer groups examine perceptions and tolerances to brief momentary interruptions and longer power outages. Benchmarking studies provide comparable reliability indicators and highlight similarities and differences in utilities' strategies to improve distribution reliability.

Targets are established each year based on past performance and new initiatives or projects which have a defined impact on the indicators.

B. HISTORICAL RELIABILITY ASSESSMENT

System outage data is automatically collected from the Trouble Call Management System. The data is analyzed to compare performance against reliability targets and identify areas for improvement.

Interruption information collected includes:

Date and time of the interruption

Length of the interruption

Customers Interrupted (CI)

Location (Circuit, Service Center, Area, etc)

Item interrupted (Feeder, Lateral, Transformer, etc)

Cause

This data can be stratified for investigation of improvement opportunities. Analysis of interruptions can identify areas requiring tree clearance, changes in lightning or fuse protection, system design changes to reduce exposure or increase sectionalizing, manufacturer defects in equipment, need for improvement in methods for installation, fault detection or repair, etc.

C. PREDICTIVE RELIABILITY ASSESSMENT

Predictive reliability of a distribution *component* or *component group* is the probability that this item will perform a given function for at least a specified period of time when used under the environmental conditions in our system.

Using historical outage data to describe component parameters and theoretical models to describe the network design, reliability of *line sections* and *system configurations* can be estimated in probabilistic terms.

Distribution planners and equipment design engineers use predictive reliability to evaluate reliability of system configurations, improve protection design, and identify restoration contingencies.

1. Component Reliability

A major component can be assigned a failure rate which represents the ratio of annual outage occurrences to the number of components in service.

- For equipment tracked and monitored in distribution equipment databases such as transformers, pad mount switches, reclosers, capacitor banks, disconnect switches, etc. the failure rates can be calculated or approximated.
- Reliability of wire/cable is approximated based on wire type and wire length.
- Some components are not tracked individually but may be grouped together or assumed to have a negligible affect on reliability.

2. Line Section Reliability

The distribution network is a radial system which consists of a series of components including Feeder breakers, switchable line sections, disconnect switches, transformers, etc. In order for a customer to have power, all components between the customer and the supply point must be operating.

To calculate the reliability of a distribution line where components are arranged in a series, experts have made simplifying assumptions that the failure rate of the line is equal to the sum of the failure rates of its components. As the number of series elements increases, the failure rate increases and thus the reliability of the line decreases.

Another simplifying assumption is that the failure rate is constant over time and each component failure is independent of the other components.

Sections of the distribution network are considered to be in parallel if the section fails only when all components fail. Such a section might be a loop system with automatic sectionalizing and throwover; a throwover with two or more sources; or a secondary network system. In these systems, the reliability of the system improves as the number of parallel elements increases.

The modeling of distribution networks becomes more complicated when protection devices and adverse weather conditions are considered.

3. Network Restoration Models

Reliability is not only a measure of the probability of failure, but the probability that the component or line section will be restored within a period of time.

The length of time it takes to locate, isolate, and repair a fault are important factors to consider in design. Installation of fault-locating equipment and cable in conduit are important for underground systems to rapidly identify and replace failed components. Other factors affecting restoration are accessibility of equipment, availability of spare parts and trouble shooting skills.

Computer programs aid in contingency planning and suggest feasible switching alternatives. Failures can be modeled and solutions generated which isolate the failed section and utilize adjacent lines to restore service to customers not directly served by the faulted section. This minimizes the number of customers remaining without service until repairs to the fault can be completed. The network dynamics are simulated by computers using estimated restoration times and load capacities.

D. RELIABILITY MAINTENANCE PROGRAMS

These programs are the result of data analysis, system modeling, and external factors. They fall into 5 categories:

1. Performance based
   Programs which address items experiencing decreasing reliability, e.g. – Multiple Interruptions
2. Inspection based
   Programs for repair/replacement of items identified during inspections, e.g. – Vault/PSIP
3. Infrastructure
   Projects which add capacity to or strengthen the Feeder grid system, e.g. – Expansion Plan
4. Regulatory
   Programs developed in response to FPSC requirements or requests, e.g. – 3% Repeat Feeder List
5. Special
   Projects which address specific geographic locations or Area customer needs

E. SUMMARY

It is best to plan reliability into the equipment and system design. Design features establish the consequences of a failure as well as the cost of preventing failures.

Flexibility in system design and sectionalizing on long feeders or laterals reduces the consequences of critical failures. Both the number of interruptions and the duration of interruptions depend on equipment design, system design, purchasing, storage, installation, operation, inspection and repair.

In addition to the total failure rate of a Feeder, cost typically increases with the number of components installed and a balance between cost and reliability must be achieved.

F. OTHER REFERENCES

Billinton, Roy and Allan, Ronald N., Applied Reliability Assessment in Electric Power Systems. Institute of Electrical and Electronics Engineers, Inc.: New York, 1991.

Billinton, Roy and Allan, Ronald N., Reliability Evaluation of Engineering Systems: Concepts and Techniques. Plenum Press: New York, 1983.

Billinton, Roy and Allan, Ronald N., Reliability Evaluation of Power Systems. Plenum Press: New York, 1984.

Section 2.1.8 has not been updated since December 2000. Please refer to the on-line version for updates prior to using. InFPL/Power Systems/Reliability/DEO/Publications/DERM

2.1.8 TRANSFORMER LOADING

A. GENERAL

There are two factors limiting the level to which the designer would normally load a transformer. These factors are voltage drop and overheating.

A given transformer has many "overload" ratings, depending upon the conditions under which it operates. The same load which could be safely carried on a cold winter night could seriously overload a pole mounted transformer on the hottest day of summer. Factors other than ambient temperature affect the overload rating. These are the load duration (or duty cycle), wind velocity, the presence or absence of rain or direct sunlight on the transformer, and the color of its paint. A transformer subjected to many years of severe loading and lightning strokes is not likely to have the capabilities of a new unit.

The term "overload" has had many interpretations within the Company and the industry. The interpretations usually infer premature failure of the transformer or excessive voltage drop, or both. At FPL, when loading causes excessive transformer voltage drop, the problem is routinely handled. However, when a transformer is known to be carrying in excess of rated kVA, questions often arise as to its ability to continue operating safely.

The balance of this section will be devoted to loading based on thermal restrictions.

The heat input into a transformer is due to the following:

11. I^2R loss due to load current. This is referred to as copper loss.
12. Hysteresis and eddy current losses in the iron laminations, mainly, but also including losses in the iron of the tank and supporting structure. These represent the main part of the "no load" loss. They are constant, regardless of the load.
13. A small I^2R loss due to exciting current is included in "no load loss".
14. Dielectric loss, in the enamel, paper, porcelain and oil. This is small and is also part of the no load loss.
15. Heat input due to sunlight or other radiated heat. This will depend on the exposure to direct sunlight and the properties of the paint.

To get rid of this heat, the transformer core and coil are immersed in an oil dielectric insulating and cooling medium. Channels are provided so the oil can flow through the coils and next to the core for good heat transfer. In distribution transformers, circulation is by means of convection currents. Hot oil from the central area, where the core and coils are, rises. This displaces oil outward and downward, forcing it to pass by the outer cooling surfaces of the tank.

The tank wall, together with any cooling tubes or fins provided, becomes a heat exchanger. It gives up the heat received from the hot oil to the outer atmosphere. Some of our transformers are dry-type. In these, the heat passes directly from the core and coil to outside air circulated through the core and coil by convection.

The efficiency of the transformer design represents a balance between full-load and no-load losses; the amount of oil, the area of the heat transfer surfaces, and the type of paint. These balances must be reached with the economics of the design kept in mind.

The copper loss is very sensitive to load since the watts going into heat energy vary as the square of the current. It is impossible to cool all parts of the winding equally. There will be one spot in the winding which, under load, gets hotter than any other spot in the transformer. This is called the "hottest-spot", and becomes one limitation on transformer load.

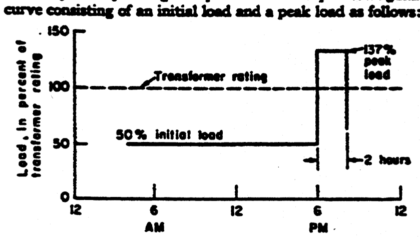
The mass of iron, copper, paper, oil, and steel in the transformer all have specific heat coefficients which introduce a time lag into any change in temperature. In addition, the cooling surfaces are continually getting rid of heat by convection and radiation. A transformer lightly loaded prior to a peak load will have a lower "hottest-spot" temperature than one carrying full load prior to the same peak load. Thus the shape of the load curve over a 24 hour period has a great effect on what peak load may be permitted on a transformer.

For winter loading, since the ambient temperatures are lower than the summer, additional load can be placed on the transformer. Strip heating loads are to determine the size of the transformer if the strip heating + full electric base load is more than 70% above the A/C + full electric base load. For example, suppose that the total winter load for a customer is determined to be 17 kVA and his total summer load is determined to be 10.6 kVA, which load should be considered to size a transformer? The answer is obtained by taking the ratio between winter and summer loads; ratio = 17 kVA/10.6 kVA = 1.60. This ratio indicates that the winter load is 60% of the summer load. Therefore, the summer load should be used to size the transformer. Unless overriding factors exists, the summer load should be used when the ratio borders on 1.70.

Most distribution transformers serve loads which are not continuous and vary widely over a 24 hour period. ANSI C57.91 shows a method of approximating these load cycles by rectangular blocks of different heights. See Figure I. The ordinates for the rectangular load curve are found by taking hourly demand readings in the lower pre-peak period, and at more frequent intervals in the peak period. The square root of the sum of the squares of the demands for the appropriate time period gives the ordinate. The duration of the peak may be chosen by inspection, but if the rectangular peak is not 90% of the highest 30 minute demand, the peak must be shortened. This precaution is to keep the hot spot in the winding from getting too hot. This curve is then converted into a curve where the ordinates are expressed in percent of rating.

The normal load cycle of distribution transformers consists of a relatively low load during the greater part of the day, with one or more peaks lasting from a few minutes to a few hours. Such a characteristic permits operating the transformer at loads in excess of its continuous self-cooled rating during short-time peaks. This is because the heat storage capacity of the transformer insures a relatively slow increase in internal temperature.

A daily load cycle might be pictured as a simple rectangular curve consisting of an initial load and a peak load as follows:



The actual daily load cycle is not usually this simple but fluctuates like the solid line below:

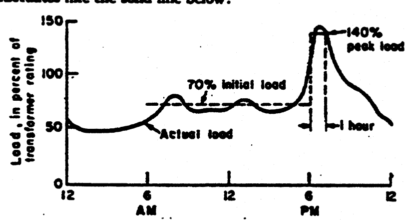


FIGURE I - EQUIVALENT LOAD CURVE FOR TRANSFORMERS

Reference: GET-2485 K

In order to use a loading guide, the actual load cycle must be converted to a thermally equivalent, simple rectangular load cycle as shown by the dotted lines. This is done in two steps.

1. Initial Load

A rough approximation can be obtained using the formula:

$$\text{Equiv. Initial Load} = 0.29\sqrt{L_1^2 + L_2^2 + L_3^2 + \text{-----} L_{12}^2}$$

where L_1, L_2, L_3 etc. is the average load, by inspection, for each one-hour interval of the 12-hour period preceding the peak load. In the curve above, this would be 70 percent of the transformer rating.

2. Peak Load

$$\text{Equiv. Peak Load} = \sqrt{\frac{L_1^2 t_1 + L_2^2 t_2 + \text{----} L_n^2 t_n}{t_1 + t_2 + \text{-----} t_n}}$$

where L_1, L_2, etc., are the various load steps in percent, per unit, or in actual kva or current and t_1, t_2, etc., are the duration of these loads, respectively. The estimated duration of the peak has considerable influence over the rms peak load. When the duration is overestimated, the rms peak load may be considerably below the maximum peak demand. In the curve above, the equivalent peak load was figured at 140 percent of the transformer rating for one hour.

The following loading guide is for self-cooled, oil-immersed transformers. The loadings are based solely on thermal and insulation-aging considerations so that voltage regulation and load losses must be considered separately by the operator for a particular system. These latter factors, perhaps not serious for loads moderately above rating, become increasingly important at higher loadings thermally permissible for short durations and low ambients.

Daily Peak Loads in Per Unit of Nameplate Rating to
Give Minimum of Twenty Years Life Expectancy

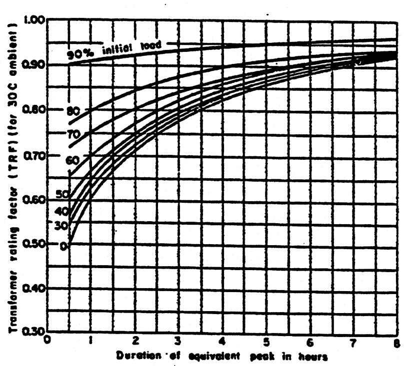
Peak Load Time in Hours	Cooling—Self-Cooled or Water-Cooled (OA or OW) (1) — Continuous Equivalent Load in Percent of Rated kva Preceding Peak Load																
	50 Percent — Ambient in Degrees C						75 Percent — Ambient in Degrees C						90 Percent — Ambient in Degrees C				
	0	10	20	30	40	50	0	10	20	30	40	50	0	10	20	30	40
1	2.52	2.39	2.26	2.12	1.96	1.79	2.40	2.26	2.12	1.96	1.77	1.49	2.31	2.16	2.02	1.82	1.43
2	2.15	2.03	1.91	1.79	1.65	1.50	2.06	1.94	1.82	1.68	1.52	1.26	2.00	1.87	1.74	1.57	1.26
4	1.82	1.72	1.61	1.50	1.38	1.25	1.77	1.66	1.56	1.44	1.30	1.09	1.73	1.62	1.50	1.36	1.13
8	1.57	1.48	1.39	1.28	1.18	1.05	1.55	1.46	1.36	1.25	1.13	0.96	1.53	1.44	1.33	1.21	1.02
24	1.36	1.27	1.18	1.08	0.97	0.86	1.36	1.27	1.17	1.07	0.97	0.84	1.35	1.26	1.16	1.07	0.95

FIGURE II

Transformer Rating Factor

The loading guide gives peak and initial loads in terms of transformer rating but it is customary to express the daily load cycle in terms of actual peak load. For example, the curve on the previous page could be stated as an initial load of 50 percent (70 ÷ 140 × 100) followed by 100 percent peak load for one hour.

Transformer Rating Factor



The chart on this page assists in determining the transformer size for serving a given load cycle. For example, assume a peak load of 58 kva for four hours following an initial load of 35 kva or 60 percent of the peak. Locating 60 percent initial load and four hours peak duration on the chart, you get a TRF of 0.86. Multiplying this by the 58-kva peak indicates a 50-kva transformer will serve this load cycle satisfactorily.

LOAD FACTOR

FIGURE III
TRANSFORMER RATING CORRECTION FACTORS
Reference - GET - 2485K

Using this curve, we determine the equivalent constant load in percent of transformer rating which preceded the peak load and also the peak duration. The proper table in ANSI C57.91 will give us the allowable peak for a given loss of life.

IEEE Standards 345-1972 (ANSI C57.100-1974) "Standard Test Procedure for Thermal Evaluation of Oil-Immersed Distribution Transformers" discusses minimum life expectancy of distribution transformers. The load on distribution transformers follows daily and annual cycles. Thus, the peak thermal loading occurs for a relatively small portion of just a few days during the annual cycle. The cumulative time at or above the rated hot spot temperature is small compared to the elapsed time. Thermal degradation is a function of temperature and time at that temperature. Thus, transformer life (elapsed time) in service should be very much greater than the life determined by an essentially continuous loading. Experience and tests indicate that an insulation system good for 60,000 hours (7 years, approximately) at rated load should give satisfactory life under the normal cyclic loading it will see in service. Acceptable thermal aging performance may be assumed if the hot-spot temperature at rated load (as defined in IEEE Std. 1-1969) does not go above that indicating a life expectancy of 60,000 hours, by the test procedure outlined in ANSI C57.100-1974.

It is not practical to have many different loading tables to cover all of the possible circumstances previously mentioned. Neither is it practical nor economical to conduct an in-depth study on every transformer suspected of being overloaded. This is especially true of very small transformers where the cost of an individual detailed analysis could exceed the price of the transformer. Large expensive transformers obviously warrant investigation if an overload is suspected.

In what follows, this section gives you some loading rules, based on average conditions, and influenced by the techniques described in ANSI C57.91. This section on Transformer Loading will answer the following two questions:

15. New installations for new loads; how do we size the transformer for anticipated load?
16. Existing installations; how much should we load them before increasing the transformer size?

Note: Loading of transformers on the Miami Secondary Network is a special situation and is not covered here.

B. TRANSFORMER INSTALLATION DESIGN

General. For transformer installations to serve new loads, the transformer size should be matched to a load equal to about 110% of its nameplate rating. Considering minimal load growth and the overload capability of a transformer, it is reasonable to design for a 20 year change out time.

In distribution design, voltage drop is a major consideration. In some situations, voltage drop and "flicker" may prevent full use of a transformer's thermal capability (see Section 2.2.1).

It has been stated that a transformer can be severely overloaded for a short period of time without exceeding its rated temperature rise. However, ANSI-C57.91 recommends that the short time loading not be allowed to exceed 250% except during an emergency. This limitation is necessary to avoid damage to the insulation at the "hottest spot" in the winding. This loading is just at or above the point where the fuse should blow on most FPL overhead transformers with standard fusing as shown in DCS I-19.

Future load growth on a new transformer installation is considered to be negligible. Transformer loading should therefore be kept to approximately 110% of nameplate rating.

C. RESIDENTIAL SUBDIVISIONS

1. Pole Mounted Installations - New Transformer Station

In choosing a transformer size, it is usually necessary to consider the technical and economic aspects of several combinations of transformer and secondary. Typical design problems are dealt with in detail in Section 4.3.2 of this manual.

2. Adding New Load to Existing Residential Transformer

It is often necessary to connect a new customer or customers to an existing transformer secondary installation. It may be possible to do this without changing out the transformer. As a general rule for residential subdivisions, customers may be added to the secondary as long as the new summer loading will not exceed 150% of transformer rating. More detailed information on this subject is given in Section 4.3.2.

3. Pad mounted, URD Subdivision

The design of the transformer-secondary system for URD subdivisions is covered in Section 5.5.1, "Residential URD Systems". Transformer loading is also covered. Transformer loading for the majority of cases should be based on serving a maximum number of customers from a transformer as shown in Section 5.5.1 Table III. This practice has validity for underground systems that may not be applicable to overhead installations.

4. Existing Installations - Load Evaluation

Presently, all transformer loading should be monitored by Transformer Load Management (TLM). The TLM system provides a calculated transformer loading by converting kWhr consumption to kVA demand.

When needed, transformer replacement, should be based on TLM data. If TLM information is not available, the following information can be used as a guide to residential transformer loading. The information is structured to cover average conditions; it is expected that a small percentage of cases will noticeably vary from the average.

Measured loading on existing residential transformers should be limited to 160% of rated kVA during hot weather and 190% if measured during extremely cold weather. Excessive voltage regulation will occur in a few cases with these loading limits.

Most often this will be at locations near the electrical end of a rural feeder and/or at the end of a long secondary bus. Where this happens, the loading limits of 160% and 190% must be reduced. It is assumed the load readings will be taken at approximate time of daily peak, and will be representative of a one hour demand period. Discard any momentary current peaks. While the 160% and 190% allowable load may seem high to some personnel, in most cases, the transformer will not be damaged. The transformer temperature does not rise to destructive levels during the short time the "overload" is carried. It should be noted that modern transformers carrying rated load operate at case temperatures in the order of 50°C, or higher; this will seem hot to the touch, but is not by itself any cause for concern.

Continuous loading in excess of a transformer's rating will of course shorten its life. This fact alone is not necessarily undesirable when economics are considered. It can be shown in come cases that a cost of a slight reduction in transformer life is more than offset by reduced capital investment.

For lack of any other means of checking loading, TLM principles may be applied manually. See SPO Procedure #21640.4. When estimating transformer load by this method, consider increasing transformer size if loading exceeds 200%. An actual load check of the suspect units is recommended.

D. TRANSFORMER INSTALLATIONS FOR LARGE INDUSTRIAL OR COMMERCIAL LOADS

1. New Installations

These installations are expensive and warrant attention to obtain accurate and complete load information.

Some points to consider:

a) Type service required; voltage, phase, ampacity, delta or wye secondary.

b) List of equipment, mode of operation, power factor, voltage, phase, amperes, and approximate load factor.

c) Transformers to be in vault or overhead?

d) Type of motor starting equipment if large motors present.

e) See also Service Planner Operations Procedures - SPO Procedure #21640 through #21640.6.

Having obtained this data, determine as closely as possible the expected demand, and duration of peak demand.

Normally, use single phase transformers up through 167 kVA to form a three phase bank. In some cases, if the size of the load requires banks to be paralleled, 3 phase units may be considered. If there is possibility of growth, design the vault and bus so another unit may be added easily.

Consider the possibility of ferroresonance, as discussed in Section 2.9.2 of this manual.

If a large wye-delta bank is to be used to serve both single and three phase load, the transformer serving the lighting and other single phase load will usually be larger than the other transformers. Assuming unequal power factors for the single phase load and the three phase load, the loading on the smaller transformers will not be equal. The transformer loads may be calculated by the following equations.

$L_A = 1/3\ (4s^2 + T^2 + 4ST \cos(\varphi_T - \varphi_S))^{1/2}$ -- Equation 1

$L_B = 1/3\ (S^2 + T^2 + 2ST \cos(\varphi_S - \varphi_T + 60^\circ))^{1/2}$ -- Equation 2

$L_C = 1/3\ (S^2 + T^2 + 2ST \cos(\varphi_S - \varphi_T + 60°))^{1/2}$ -- Equation 3

Where S = single phase load in kVA; φ_s = single phase power factor angle.

T = Three phase load, kVA; φ_T = Power Factor angle, three phase load.

L_A = Load on Transformer A across which single phase load is connected.

L = Load on transformer B connected to phase lagging the phase to which transformer A is connected by 120°.

L_C = Load on third transformer, C.

Usually it is sufficiently accurate, when selecting transformer sizes, to assume

$L_A = 1/3\ T + 2/3S$ -- Equation 4

$L_B = L_C = 1/3T + 1/3S$ -- Equation 5

An advantage of the wye-delta bank, with wye point not grounded, is that the wye point will shift to allow the bank to compensate for primary voltage unbalance. It will furnish balanced voltages to a balanced three phase load. Single phase load will cause some unbalance in voltage.

Wye-wye banks may have single phase loads distributed equally between phases, so they can have equal loads on each transformer. If transformer impedances are equal the wye-wye bank will not cause unbalanced voltages for balanced loads. However, it will not correct for primary feeder voltage unbalance. Pad mounted transformers are available with the wye-wye connection, but not with the closed delta connection.

Regardless of the type of bank used, the transformer sizes should be chosen to match the proposed transformer load as closely as possible. Loading on the transformers should not exceed 110% of nameplate rating initially.

If the transformers are in a vault, ventilation must be provided.

If there are large motors present, consideration must be given to possible flicker problems (see Section 2.2.1).

The larger transformers will have top-oil temperature gauges. These should be monitored by persons visiting the vault to see that temperature limits are not exceeded.

2. EXISTING TRANSFORMERS SERVING INDUSTRIAL AND COMMERCIAL LOADS - LOAD EVALUATION

This discussion is intended to cover the loading of only the larger and more expensive transformers. In almost all cases, customers served by these transformers have a demand meter. A customer's demand history often provides valuable insight into a suspected transformer overload.

Transformer capacity should be increased if any of the following conditions are noted:

f. The kW billing demand records indicate that 105% of the rated transformer kVA has been exceeded for 3 or more months of the year.

g. The transformer is carrying near rated load and the top oil temperature gauge indicates a temperature of 100°C or greater for 65° C rise transformers, or 90° C for 55° C rise transformers.

h. When a transformer serves more than one customer and any one customer's demand equals or exceeds the transformer rating.

Provided the transformer is in good condition, replacement need not be made an emergency under the above conditions. Extreme cases excepted, only slight loss of transformer life will result if the transformer is replaced during normal working hours.

The above loading guide presumes an average customer's power factor of 0.85. The 105% loading translates to 105%/0.85 or 124% of rated kVA. The loading limits are lower than those suggested for residential transformers to allow for the longer duration of peak loads of industrial and commercial customers.

Special cases too numerous to list will arise which may require transformer replacement. These situations should be decided on the judgment of experienced personnel.

E. SMALL COMMERCIAL CUSTOMERS

1. New Transformer Installations

These customers usually have a large single phase load, with a small three phase load.

Obtain data from the customer which will allow you to establish the single phase and the coincident three phase demand. An open-wye, open-delta bank is a good way of serving this type of load. It is not likely to give ferroresonance problems. Under some combinations of single and three phase load it will give more nearly balanced voltages than will the closed wye-delta. It will not compensate for unbalanced primary voltages, and will cause some voltage unbalance when the load is a balanced three phase load.

Open-wye banks in an area should be apportioned as equally as possible to the three phases, to prevent unbalanced line currents.

The open-wye, open-delta bank should be satisfactory at 4 kV for all three phase loads below 37 kVA; at 13 kV for three phase loads 75 kVA and below and at 23 kV for all loads except very large three phase loads. At 23 kV, ferroresonance is a consideration and is avoided by the use of an open-wye, open-delta bank.

The transformer supplying the single phase lighting load should be connected to the leading phase. The load on this transformer will be:

$$L_L = (S^2 + {}^{T^2}/_3 + {}^2/_3 \; ST \cos(\varphi_T - \varphi_S + 30°))^{1/2} \text{ -- Equation 6}$$

and the load on the "kicker" transformer will be:

$$L_K = {}^1/_3 \; T = 0.577T \text{ kVA -- Equation 7}$$

Assuming $PF_3 = 0.8$ and $PF_1 = 0.95$, from Equation 6

$$L_L = (S^2 + {}^{T^2}/_3 + 0.76\ ST)^{1/2}$$

suppose S = 30 kVA

T = 15 kVA

$$L_L = ((30)^2 + \frac{(15)^2}{3} + 0.76\ (30 \times 15))^{1/2}$$

$$= (900 + 75 + 342)^{1/2} = (1317)^{1/2} = 36.3 \text{ kVA}$$

In most cases, it will be sufficiently accurate to say $L_L = S + 0.577T$.

$L_K = 0.577 \times 15 = 8.7$ kVA.

This would call for a 37 1/2 and a 7 1/2 or 10 kVA transformer.

If a pad mounted installation is required, we do have a number of duplex open-wye, open-delta units we would like to use up. If you do not have the right size duplex unit, you may use two single phase pad mounted transformers - See FPL DCS I-68.

There may be cases where 4 wire, three phase, service at 120/208 volts, or 277/480 volts is required. This may be furnished from three pole mounted aerial type transformers, or in underground areas from the same transformers equipped with cover mounted potheads and located in a customer-furnished vault. In appropriate areas, three phase pad mounted transformers are available.

Initial loading allowed on an open-wye, open-delta bank depends on the type of three phase load it is serving. As mentioned before, some unbalanced voltage is caused when serving a balanced three phase load. This is not much of a problem for a lightly loaded motor, or one which runs intermittently for short periods. For a heavily loaded three phase motor, which runs for long periods at a time, unbalanced voltages can cause overheating and failure. This situation is often found in commercial three phase refrigeration motors, deep well pumps, and in three phase unitary air conditioning units. When the bank is serving this type of load, it is suggested that the initial design loading of the transformer carrying the lighting load be limited to 90% of nameplate. The kicker transformer may be loaded 100% of nameplate.

Both transformers may be loaded initially to 100% of nameplate capacity if:

a. There are none of the described types of loaded three phase motors, or

b. The rating of the described type of loaded three phase motors is small compared to the bank capacity (say 1/4 or less of the transformer capacity).

If service is from a wye-wye bank, initial design loading may be equal to nameplate rating.

2. Existing Installations - Load Evaluation

Several of these small commercial customers may be grouped on one transformer, or each may be isolated. Drug stores, 7-11's, neighborhood hardware stores, restaurants with gas cooking, general stores, neighborhood men's and women's clothing stores, and others would come under this heading. Their load would be reasonably constant, and in most cases would last for 8 hours or more with minor peaks of shorter duration. If demand meters are not present, load checks must be made when overload is suspected; see SPO Procedure 21640.5. Many of this type of customer are served from open wye - open delta banks where overloading will aggravate any existing voltage unbalance.

If there are no pending complaints of unbalanced voltage conditions, transformers may be loaded to 150% of nameplate kVA before changeout is indicated.

F. IRRIGATION AND FROST CONTROL PUMPS OR FANS

1. New Transformer Installations

The load factors for these types of installations are low. In addition, the ambient temperature at the time the frost control equipment is used is low. This would indicate that a considerable overload may be allowed without damaging the transformer. Balanced against this is the fact that these services are essential to the grower when needed. If a transformer fuse blows when the frost control equipment is needed, the crop may be lost before the fuse can be replaced. It is advisable to follow the same rules for this type of service as for the new industrial and commercial loads. See D.1., this section.

2. Existing Installations - Load Evaluation

If there is a demand meter on the installation, assume a power factor of 0.85 and convert kW demand to kVA demand. If there is no demand meter, it may be necessary to make a test run so that the load current can be measured. As a last resort, consider the load to be the full nameplate kVA of the motor or motors. The transformer loading should not be allowed to exceed 170% of nameplate rating. If there has been operating trouble traceable to the bank, further investigation and load checks should be made. Be sure the trouble was due to the bank, and not feeder trouble.

G. NOTES ON TRANSFORMER LOAD MEASUREMENTS

16. Load Factor, based on transformer kVA =

$$\frac{\text{monthly kWh (Sum of all customers served)}}{\text{P.F. x Transf. kVA x hours in month}}$$

This gives you an idea of the average load on the transformer.

2.2.1 VOLTAGE REGULATION - MOTOR STARTING

The starting of large electric motors may cause a sudden change in the voltage of the distribution supply system. In order to determine the impact on customers connected to the supply distribution feeder, as well as all other customers on feeders connected to the same Power transformer at the Substation, it is necessary for the Planning Engineer to conduct a Motor Starting Study for large motors. The Planning Engineer will determine the distribution feeder service method and any required special Motor Starting equipment.

A. MOTOR STARTING CHART

The discussion which follows deals with the type of installations most frequently found. These are three-phase induction motors of 500 horse power or less with a rated nominal voltage of 480 volts or less. Full voltage starting is assumed. The effects of reduced voltage starting devices should be included in the final calculation if they are used.

The charts for 13 kV and 23 kV primary which follow were produced to give a reasonable approximation of voltage drop that can be expected during motor starting. They should be useful during negotiations with the customer for a proposed installation. Frequently during negotiations, insufficient information is known with which to make more exact calculations. The charts do not take into account the impedance of the transformer bank which will serve the motor. When the bank is included, the voltage fluctuation seen by the motor customer will be greater than shown by the charts. The fluctuation seen by other customers not served by the bank will be less than shown by the chart because the impedance of the transformer bank tends to reduce the motor starting kVA. To get a more accurate solution including the transformer impedance, calculations must be made, as shown under "Calculation Methods".

The use of charts is straightforward provided that the magnitude of the available primary fault current and the horsepower of the motor are known. The use of SynerGEE is the recommended preferred method.

1. Example Case Illustrating Use Of Chart - Figure 1:

The customer's proposed motor is a 300 horsepower induction motor. The FPL primary voltage is 7620/13200 volts, and the available primary fault current is 1951 amps. The 1951 amps could have been obtained from the SynerGEE Program Fault analysis report for the designated feeder. (For purposes of this illustration, it was derived by the expression 7620 volts/3.905 ohms, where the 3.905 ohms is the accumulated system impedance up to the transformer bank serving the motor.)

A line is drawn vertically upward on the 1951 amp line until it intersects the 300 hp motor curve. A line drawn horizontally to the right from the intercept point intersects the % voltage drop axis at about 3.75%. Thus the approximate primary voltage drop in this selected case is 3.75%. As will be shown later in this section, detailed calculations give an answer of 3.51% drop for the same case. The calculation however can only be done when dependable information becomes available which is usually later in negotiations.

B. CALCULATION METHODS

The motor starting calculations may be performed manually or by using the SynerGEE program. In either case, the data required for calculation is the same. Consult the SynerGEE training manual for details on running the program. Examples of the input and output screens from SynerGEE are found on Figures 2 through 4. Following is the methodology for performing the calculations manually. The accuracy of motor start voltage drop calculations depends mainly upon the accuracy of the furnished data and the attention to detail in its application.

For exacting work, the following must be known:

1. The Motor

a) Type, i.e., induction, synchronous or wound rotor.

b) Horsepower, design class and code letter OR locked rotor power factor and kVA.

c) Rated voltage.

d) The type of starter used and the frequency of starting.

2. The Supply Circuit

e) The resistance and reactance of the primary circuit and of the system. The information is available from Distribution Reliability Planning.

f) The resistance and reactance of the transformer bank serving the motor and of any appreciable secondary conductors between the transformer bank and the motor.

g) The actual - not nominal - secondary voltage at the transformer bank prior to the time the motor starts.

Since some of the above required data may not be available, or may not be constant, such as the primary voltage - assumptions have to be made in order to proceed with the calculations. The following assumptions have been made:

1. The equivalent impedance of the motor at standstill is constant over the range of voltages encountered at starting. This is not entirely correct. The magnetization curve of the motor's iron is not linear. Applying a correction factor proportional to ^{E}actual/^{E}rated gives a starting current somewhat low for actual voltages above motor rating, and somewhat high for voltages below motor rating.

2. The voltage at the motor prior to starting is equal to the normal voltage of the FPL transformer bank which serves the motor. For example, at a 480 volt installation, the transformer secondary voltage and the rated motor voltage is 480 volts. This will not necessarily be true because the transformer voltage can vary between 456 volts and 504 volts and remain within the 7-1/2% statutory limits. Also, the rated motor voltage could be 440 volts, 450 volts, 460 volts and perhaps others. If a great disparity between delivered and rated voltage exists, and its value is known, the effect can be accounted for. Adjust the inrush current proportional to the voltage, i.e., the ratio of delivered voltage to motor rated voltage. As noted above, this is not precisely true, but is accurate enough.

3. The driving voltage at the source remains constant.

4. For induction motors, the starting kVA and locked motor power factors are:

HORSEPOWER	STARTING kVA	STARTING P.F.
50	289	0.37
100	578	0.32
200	1155	0.25
300	1753	0.22
400	2311	0.20
500	2888	0.18

Motor start line disturbance solutions can be made either by the per unit system or by using ohmic values. Some approximation methods tend to disregard resistance values. This does not materially affect the answer when the X/R ratio is high, but the error increases in magnitude as the ratio decreases. This usually happens when conductor sizes decrease as the feeder lengthens. Those personnel skilled in voltage flicker approximation methods are aware of the foregoing and thus require no further comments. Therefore, only the ohmic method of solution will be illustrated.

3. Example

A proposed motor is a 300 horsepower, NEMA design (NEC Code Letter G) induction motor with a locked motor kVA of 1753 at 22% power factor. The primary voltage is 7620/13200 and the accumulated impedance up to the transformer bank is 1.25 + j 3.7 ohms. The transformer bank is 500 kVA (3 @ 167 kVA) with an impedance of 3.23 + j 6.75 ohms. All impedances are line to neutral values, primary side.

Equivalent line to neutral motor starting impedance, Zm

1753 kVA/3 = 584.33 kVA per phase

$Zm = (KV)^2/MVA = (7.62)^2/0.58433 = 99.37/\cos^{-1}(0.22)$ ohms

rm = 99.37 cos θ = 99.37 x 0.22 = 21.86 ohms

xm = 99.37 sin θ = 99.37 x 0.9755 = 96.4 ohms

Where rm and xm are, respectively, the equivalent line to neutral resistance and reactance, on 7.6kV base, of the motor while starting.

Summation of all series impedances, Zs

1.25 + j 3.7 (accumulated impedance of the system, in ohms, up to transformer)

3.23 + j 6.75 (Transformer bank impedance, in ohms, primary side)

21.86 + j 96.94 (motor starting impedance, in ohms, on 7.6kV base)

26.34 + j 107.39; ^{Z}s = 110.57/76.22º_ ohms (Total)

Primary line current, Istart

^{I}start = $^{E/Z}$s = 7620/0º/110.57/76.22º = 68.92/-76.22º amps

Primary voltage drop, Vd, up to transformer bank, i.e., affecting other customers

^{V}d = I (r cos θ + x sin θ) = 68.92 (1.25x0.22+3.7X0.9755) = 267.71 volts or 3.51%

The flicker caused by the customer's motor is more severe on his own property than to other customers not served by the same transformer bank. The customer should be advised that, while it may be agreeable to FPL for his proposed motor to be started across-the-line, his motor could cause an objectionable disturbance to his own service. In this example, the flicker seen by the "motor" customer is:

^{V}total = I(r cos θ + x sin θ); where r = 1.25 + 3.23 = 4.48 ohms

and x = 3.7 + 6.75 = 10.45 ohms

^{V}total = Drop from source to transformer secondary terminals.

= 68.92 (4.48 x 0.22 + 10.45 x 0.9755)

^{V}total = 770.5 volts or 10.11%. This does not include voltage drop in service or customer's motor circuit.

This 10.11% voltage drop could be entirely acceptable to the customer if the motor starts only infrequently, for instance, once per day.

Effect of Reduced Voltage Starters.

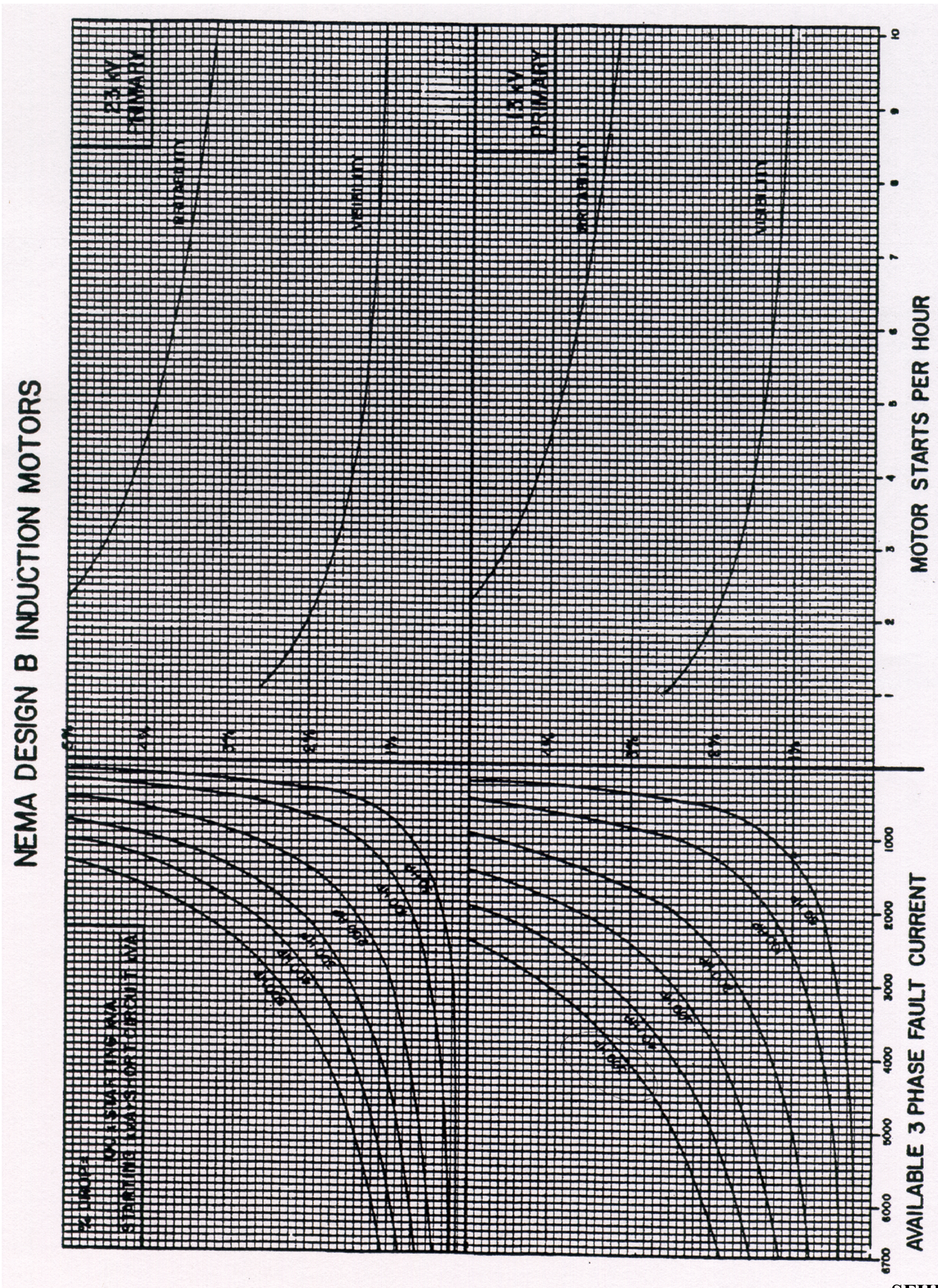
The values of percent voltage drop obtained from the graph on Figure 1 are for "across-the-line" starting. If reduced voltage starters, or part-winding starters are used, these values should be multiplied by the following factors (k):

Two step part winding; k = 0.60
80% Tap, auto-transformer; k = 0.66
65% Tap, auto-transformer; k = 0.45
50% Tap, auto-transformer; k = 0.27

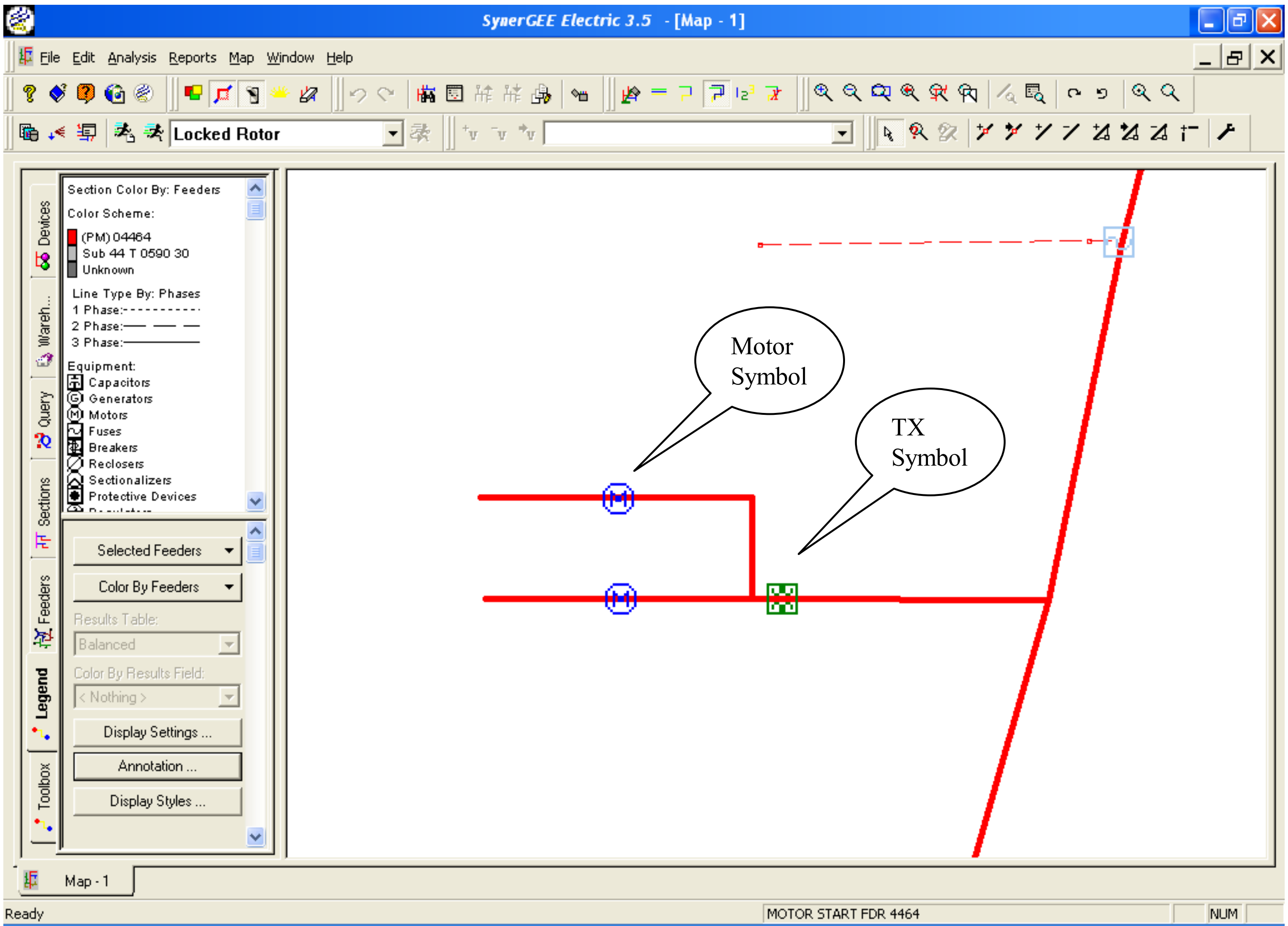
Locked, motor currents are roughly proportional to the square of the voltage (decimal remainder). The factors above exceed the squared values slightly, because of slightly higher line voltage that exists ahead of the starter due to reduced load kVA and slightly lower power factor.

Primary Voltage Flicker Limitation Policy (Revised on 12-8-09 by SC)

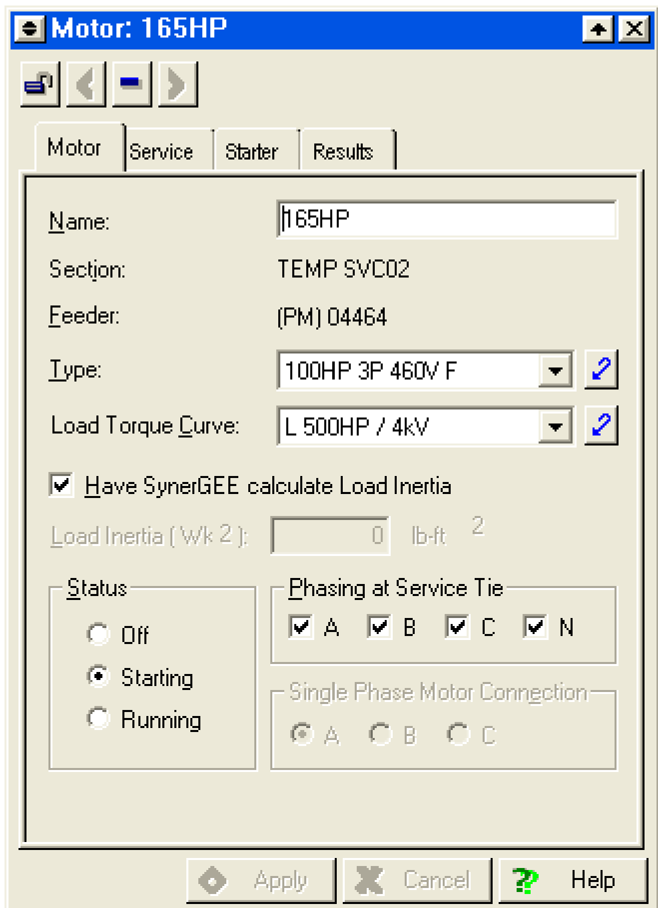
The percent Primary Voltage Flicker due to motor starting should be limited to 2.5% or below.
Use the "Visibility" curve below to determine the maximum voltage flicker allowed based on the number of motor starts.
The maximum %Voltage Flicker allowed should be 2.5% for a motor expected to start one or less times per hour.



Motor modeled into the Distribution System:



Motor Editor:



Output Report for locked Rotor Analysis:

Section	Before	During			After	
(or Device)	Volts (120V)	Volts (120V)	Pct	Amps	Volts (120V)	Amps
Name	Bal	Bal	Dip	Bal	Bal	Bal
39361432	117.3	116.6	0.60%	4	117.1	4
39361317	117.3	116.6	0.60%	4	117.1	4
41401514	117.2	116.5	0.60%	296	117	294
41401489	117.2	116.5	0.60%	295	117	293
41365649	117.1	116.4	0.60%	295	116.9	293
Dummy 39358807	117.1	116.4	0.60%	4	116.9	4
39358937	117.1	116.4	0.60%	4	116.9	4
39358837	117.1	116.4	0.60%	4	116.9	4
41367380	117.1	116.4	0.60%	291	116.9	289
TEMP SVC	117.1	116.4	0.60%	14	116.9	8
TEMP SVC03	116.9	112.3	3.90%	34	115.9	33
TEMP SVC04	116.8	112.3	3.90%	34	115.8	33
Mtr 30 HP	116.1	111.5	3.90%	34	115.1	33
TEMP SVC02	116.9	111.5	4.60%	375	115.6	180
Mtr 165HP	116.9	64.3	45.00%	649	115.6	180

17. The kW demand of a customer at the time of test can be obtained from the watthour meter, even if it does not have a demand register. Obtain the watthour constant, k_h from the meter nameplate. With a stop watch, measure the time t, in seconds for 10 revolutions of the disc.

$$\text{The kW Demand} = \frac{\frac{Kh \times 10}{t}}{3{,}600} \times 1{,}000$$

For instance, suppose k_h = 6.0 watthours/revolution, t = 16 seconds (measured, for 10 rev.)

$$\text{kW Demand for 16 Sec. Period} = \frac{\frac{6 \times 10}{16}}{3600} \times 1000 = \frac{60 \times 3.6}{16}$$

=13.5 kW

18. In checking loading of single phase transformer feeding 120/240 volt secondary if I, and I_2 are the currents on the transformer secondary "hot" leads, then kVA.

$$\text{Load} = \frac{I_1 + I_2}{2} \times \frac{240}{1{,}000}$$

19. Buses paralleled at the transformer and the load end may not share load equally. If buses are identical, check bus length from feedpoint to the load. Unequal lengths can cause unequal loadings. Preferably, parallel at the load only. Then each transformer and bus impedance becomes a unit.

20. If a three phase wye-wye transformer heats up unaccountably, even though not overloaded, check to see if it has a three legged core. A short on one phase of the primary or secondary could blow one fuse. The shorted turns would cause that leg of the core to offer a high impedance path to the resultant flux from the other two legs. Some of it would be shunted through the iron case and could cause tank heating, even to the extent of paint damage. The transformer itself may not have been damaged. This could also happen without blowing a fuse if an overhead conductor on the load side of fuse broke and fell to ground, while the side attached to the cutout stayed in the clear. We now specify 5 legged cores or triplexed units for all wye-wye three phase units to prevent tank heating.

21. Portable fans may be used to cool transformers in a vault during an emergency.

22. Thermovision, if available, can spot overheated transformers.

23. When measuring the loading of a transformer bank with delta secondary, measure the current in each individual transformer lead to determine loading on each transformer.

24. When checking voltage unbalance on a three phase motor served from an open-delta transformer bank, the unbalance is considered acceptable if the ratio of negative sequence voltage to the positive sequence voltage does not exceed 0.025. Knowing the phase to phase voltages, this ratio can be calculated by the methods of symmetrical components. It can also be obtained from Figure IV. Suppose the phase voltages are 232, 237, 242. The ratio of Medium to Largest, $M/L = \frac{237}{242}$

=0.979; the ratio of Smallest to Largest, $S/L = \frac{232}{242}$ = 0.959. Entering the chart, we find N/P =0.0252, which is so close to 0.025 that we would call it acceptable, within our limits of measurements.

25. Excessive primary voltage will drive the transformer magnetization curve farther into the saturation region. This will increase the harmonic voltages generated. Capacitor bank harmonic currents will increase. Telephone interference may develop.

26. Explanation of nameplate for transformer voltage ratings are shown on Figure III. This data is from ANSI C57-12.00, 1973.

27. Load Factor

Load factor has a bearing on the heating and subsequent damage to overloaded transformers.

A few annual load factors for different types of occupancies in the Miami Area computed in October 1978 are given. These are not necessarily typical of your area, or even of the Miami Area, but may be helpful.

Type of Occupancy	Annual Load Factor, %		
	MIN	MAX	AVG
Apartments (Avg. of 422)-No A/C	55.9	56.2	56.1
Apartments (Avg. of 1583)-A/C	59.9	73.6	67.1
Post Office-1--A/ C	--	--	78.0
Supermarkets-(Avg. of 6)-A/C	66.6	80.7	73.5
Hospitals (Avg. of 22)-A/C	58.2	78.7	73.7
Hotels-(Avg. of 5)-A/C	58.0	79.9	73.0
Office Bldg. (Avg. of 32)-A/C	31.6	73.4	46.8
Large Department Retail Store (Avg. of 7)-A/C	31.4	52.8	45.0

28. Converting Secondary Loading Readings to Transformer Load Currents on Closed Delta Bank

Draw a triangle to scale with the sides equal to the three secondary load readings in amperes. Connect the midpoint of each side to the opposite vertex. The three lines will intersect. The scaled distance from the vertices to the point of intersection represent transformer load currents.

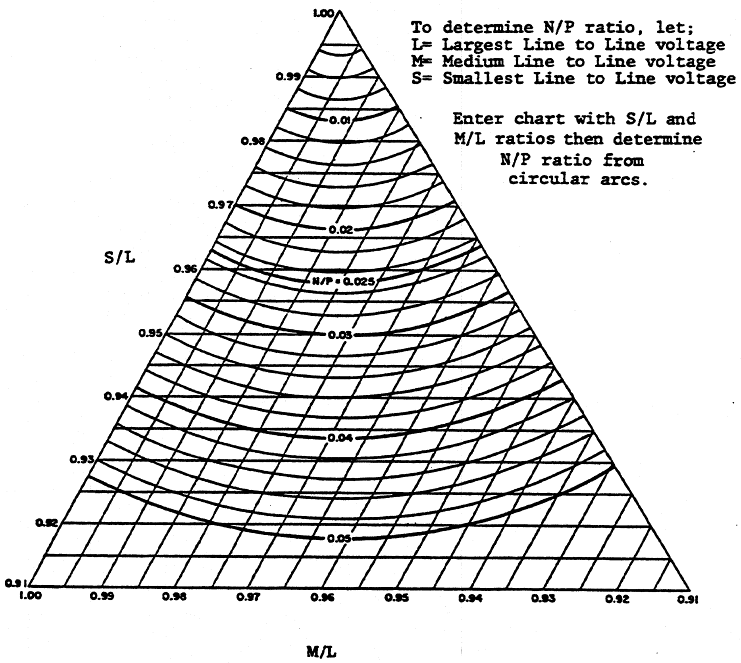
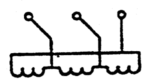
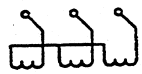
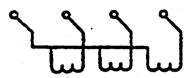
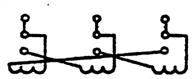
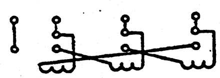
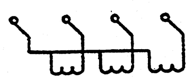
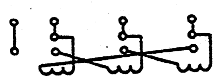
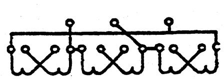
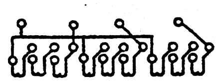


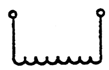
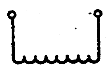
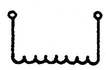
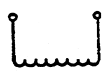
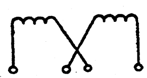
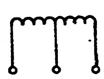
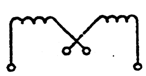
Figure IV

Chart for Determining Ratio of Negative Sequence to Positive Sequence Voltage
(See Paragraph G-9 on Preceding Pages)

Identi-cation	Nomenclature	Nameplate Marking	Typical Winding Diagram	Condensed Usage Guide
(2) (a)	E	2400		E shall indicate a winding which is permanently Δ connected for operation on an E volt system.
(2) (b)	E_1Y	4160Y		E_1Y shall indicate a winding which is permanently Y connected without a neutral brought out (isolated) for operation on an E_1 volt system.
(2) (c)	E_1Y/E	4160Y/2400		E_1Y/E shall indicate a winding which is permanently Y connected with a fully insulated neutral brought out for operation on an E_1 volt system, with E volts available from line to neutral.
(2) (d)	E/E_1Y	2400/4160Y		E/E_1Y shall indicate a winding which may be Δ connected for operation on an E volt system, or may be Y connected without a neutral brought out (isolated) for operation on an E_1 volt system.
(2) (e)	$E/E_1Y/E$	2400/4160Y/2400		$E/E_1Y/E$ shall indicate a winding which may be Δ connected for operation on an E volt system or may be Y connected with a fully insulated neutral brought out for operation on an E_1 volt system with E volts available from line to neutral.
(2) (f)	E_1GrdY/E	67 000GrdY/38 700		E_1GrdY/E shall indicate a winding with reduced insulation and permanently Y connected, with a neutral brought out and effectively grounded for operation on an E_1 volt system with E volts available from line to neutral.
(2) (g)	$E/E_1GrdY/E$	38 700/67 000GrdY/38 700		$E/E_1GrdY/E$ shall indicate a winding, having reduced insulation, which may be Δ connected for operation on an E volt system or may be connected Y with a neutral brought out and effectively grounded for operation on an E_1 volt system with E volts available from line to neutral.
(2) (h)	$V \times V_1$	7200 × 14 400 4160Y/2400 × 12 470Y/7200	 	$V \times V_1$ shall indicate a winding, the sections of which may be connected in parallel to obtain one of the voltage ratings (as defined in a, b, c, d, e, f, and g) of V, or may be connected in series to obtain one of the voltage ratings (as defined in a, b, c, d, e, f, and g) of V_1. Windings are permanently Δ or Y connected.

Key: $E_1 = \sqrt{3}E$

Designation of Voltage Ratings of Three-Phase Windings (Schematic Representation)

Identi-cation	Nomenclature	Nameplate Marking	Typical Winding Diagram	Condensed Usage Guide
(1) (a)	E	34500		E shall indicate a winding of E volts which is suitable for Δ connection on an E volt system.
(1) (b)	E/E_1Y	2400/4160Y		E/E_1Y shall indicate a winding of E volts which is suitable for Δ connection on an E volt system or for Y connection on an E_1 volt system.
(1) (c)	E/E_1GrdY	38 700/67 000GrdY		E/E_1GrdY shall indicate a winding of E volts having reduced insulation which is suitable for Δ connection on an E volt system or Y connection on an E_1 volt system, transformer neutral effectively grounded.
(1) (d)	E_1GrdY/E	12 470GrdY/7200		E_1GrdY/E shall indicate a winding of E volts with reduced insulation at the neutral end. The neutral end may be connected directly to the tank for Y or for single-phase operation on an E_1 volt system, provided the neutral end of the winding is effectively grounded.
(1) (e)	E/2E	120/240,240/480		E/2E shall indicate a winding, the sections of which can be connected in parallel for operation at E volts, or which can be connected in series for operation at 2E volts, or connected in series with a center terminal for three-wire operation at 2E volts between the extreme terminals and E volts between the center terminal and each of the extreme terminals.
(1) (f)	2E/E	240/120		2E/E shall indicate a winding for 2E volts, two-wire full kVA between extreme terminals, or for 2E/E volts three-wire service with ½ kVA available only, from midpoint to each extreme terminal.
(1) (g)	V × V_1	240×480 2400/4160Y×4800/8320Y		V × V_1 shall indicate a winding for parallel or series operation only but not suitable for three-wire service.

Designation of Voltage Ratings of Single-Phase Windings (Schematic Representation)

H. OTHER REFERENCES

29. See Latest Revisions of ANSI Transformer Standards C-57.12.; C-57.1200 A & B; C-57.12.00; C-57-12.21-199; C-57.12.21; C-57.12.22; C-57.12.25; C-57-12.26; C-57.12.70; C-57.12.80; C-57-12.90; C-57-12.90a; C-57.91; C-57-12.98;C-57-105-1978

30. Westinghouse Electric Utility Engineering Reference Book, Distribution systems, 1959, Chapter 6.

31. IEEE Transactions on Power Apparatus and Systems, Jan/Feb 1979 (Volume PAS-98) Number 1, Page 159, F-78 696-7.

32. General Electric Publication "Distribution Transformer MANUAL GET - 2485K."

2.2.2 FEEDER VOLTAGE REGULATION

A. VOLTAGE REGULATOR APPLICATION

1. SUBSTATION REGULATION

Voltage levels of the power transmission system may vary over a wide range with changes in system load flow. These voltage variations will appear at the distribution substation bus. The customer sees not only this voltage variation, but also variation due to feeder, transformer, secondary and service voltage drop. The sum of these variations may well exceed our established limits ($\pm$ 5% for most customers) unless some type of correction is applied.

It has been found that in most cases if the feeder source voltage can be properly controlled, satisfactory customer voltage can be maintained.

Controlling the feeder source voltage is accomplished by feeder voltage regulators, or in some cases self regulating (LTC) station transformers. Self regulating station transformers have a built in regulating mechanism. Their only disadvantage is that the regulation can not be applied on an individual feeder basis. This generally is not a great problem where all of the substation feeders have the same characteristics.

2. LINE REGULATION

Line regulators, for the most part, are identical to station regulators except that their current ratings are usually lower. Long feeders may have excessive voltage drop under peak load conditions, making it necessary to place regulators at some point out on the feeder in order to obtain acceptable customer voltage. Application of line regulators follows the same principles as station regulators.

Some single phase line regulators are light enough to be pole mounted. It is sometimes advantageous to mount one regulator on each of three poles for a three phase line. An alternative is a platform, or a mat on the ground.

B. SPECIFICATION OF FEEDER REGULATOR SETTINGS

1. CRITERIA

Feeder regulator settings must satisfy the requirement that the feeder voltage profile be within acceptable limits. This must be true for all likely combinations of load current and power factor.

In addition, it is desirable that:

cc) Large voltage swings over a 24 hour load cycle at any point be minimized wherever possible.

dd) There be a voltage rise in primary voltage on peak (secondary-compensation) to overcome secondary voltage drop.

ee) Feeder voltages not be unnecessarily high, especially at light load. High voltage causes increased transformer core losses due to over-excitation. It also shortens the life of lamp bulbs and some appliances.

ff) Excessive regulator operations be minimized and "hunting" be eliminated through proper selection of bandwidth and time-delay settings.

2. EXPRESS SECTION LINE DROP COMPENSATION SETTINGS

In some cases a feeder will run a significant distance from the substation before reaching the first customer. This portion of the feeder between the substation and the first customer is often called an "express" section. By selecting the proper line-drop compensation settings, voltage may be regulated at the first customer instead of at the regulator output. This is known as express section compensation.

The "first customer" may be defined as the first load served which requires that the primary voltage be kept within certain limits. This restriction is necessary in order that the delivered voltage will be maintained within the Company's established voltage limits. Normally the upper limit will be 126 volts. Feeders having the "first customer" very close to the substation will have no express section and hence will require no express section compensation. The installation of capacitors on the express section of a feeder is to be discouraged. If capacitors are connected to this portion of the feeder it may be necessary to calculate special regulator compensation settings.

In order to establish correct settings for express section compensation, R_1 and X_1, it will be necessary to know the resistance (R_L) and reactance (X_L), of the express section in ohms/phase. The compensation settings may be found by:

$$R_1\,setting = \frac{CT_P\, R_L}{N_{PT}}$$

$$X_1\,setting = \frac{CT_P\, X_L}{N_{PT}}$$

Where CT_P = Primary rating in amperes of regulator current transformer and N_{PT} = Ratio of the regulator potential transformer.

By definition, the "beam voltage" is the setting at which the contact making voltmeter beam will be balanced and will make neither "raise" nor "lower" contacts. The beam voltage differs from the output voltage by the voltage drop in the line drop compensator, taking the P.T. ratio into account. See also Section 3.8, page 3.

Express section compensation is independent of the beam voltage setting. If over-compensation is desired, it must be added to the express compensation. For procedure to request change in compensator setting, see Procedures # 2613.1.

3. BEAM AND LINE DROP COMPENSATOR SETTINGS

These settings must be considered together since they are interdependent. These settings are, however, independent of express section compensation. If there is an express compensated section, just visualize the regulator as being at the load end of this section. Any line drop compensator settings will be added to the express compensation settings to yield the total compensation.

Under this heading we will be dealing with beam volts and volts of compensation as seen by the feeder and referenced to a 120V base. The beam setting may be found by:

$$V_B = \frac{V_{BF}\, N_L}{N_{PT}}$$

Where V_B = Regulator beam setting, V_{BF} = The desired beam voltage, N_L = Line transformer ratio (Primary/Secondary) and N_{PT} = Regulator PT ratio. The following examples are for 13kV and 23kV feeders respectively with standard regulator PT ratios and a 123v beam setting.

$13kV$

$$V_B = 123v = \frac{123v(7.621kV/120v)}{63.5}$$

$23kV$

$$V_B = 123v = \frac{123v(13.2kV/120v)}{110}$$

a. Substation Regulator Settings

The average feeder is generally less than 25.0 kft. in length. The load center of such a feeder usually lies between 1/2 and 2/3 the total length. Conductor sizes are generally 343T, its equivalent, or larger. Peak loads may be anywhere from 200 to 400 amperes under normal conditions, and can approach 600 amperes during emergency switching. 400 amperes is usually the practical limit for normal loading, and with a fully corrected power factor, the total voltage drop at the end of the feeder usually will not exceed 4 volts. Fixed and switched capacitors are normally applied such that the power factor is reasonably corrected for most load conditions year-round. The uncorrected feeder kvar demand hardly ever exceeds $\pm$ 1500 kvar, and on most feeders is much less than this.

In order to prevent excessive voltages during emergency conditions and eventually with load growth, it is recommended that line drop compensation be applied based on 400 amperes. The combination of beam voltage and line drop compensation at 400 amperes should not exceed 126 volts.

A beam setting of 123 volts plus 3 volts of line drop compensation at 400 amperes will achieve excellent results, and satisfy most of the criteria listed in B.1.

It should be noted that a voltage regulator at the substation cannot effectively overcome the excessive voltage drop which will occur on feeders with poor power factor correction. On a 343T feeder with a .90 natural power factor, the voltage drop will be almost double that of the same feeder and kw load with the power factor corrected by proper application of capacitors.

With good power factor correction, the recommended 3 volts line drop compensation should be entirely resistive, with zero reactive compensation. The use of 1 or 2 volts reactive "X" compensation has a negligible effect on regulator output on this type of feeder and serves no useful purpose.

Should a feeder have a poor power factor, and for some reason correction with capacitors is not feasible, then carefully selected "R" and "X" line drop compensation settings can minimize excessive line voltage drop. In this case, for compensation to be proportional to line drop, the X to R compensation ratio should equal the x to r ratio of the line impedance.

This latter type of line drop compensation will establish a point of regulation (a point on the line where the voltage will be held at the beam voltage for all load and power-factor conditions) somewhere out on the feeder beyond the regulator and express section. The maximum amount of compensation will be limited by the maximum permissible voltage at the first customer for all load and power factor conditions.

The use of "secondary compensation" is a special case of line drop compensation which is often misunderstood and rarely used. The purpose of secondary compensation is to produce a boost in primary voltage at the distribution transformer which will compensate for the voltage drop in the transformer and secondary. The R and X settings are chosen to correspond to a typical transformer and secondary impedance. True secondary compensation cannot normally be attained on our feeders for two reasons. First, the use of distribution capacitors prevents the regulator compensator from seeing the true power factor of the average secondary system, and secondly, the voltage drop on most feeders is such that it is impossible to establish this boost on peak at the load center.

To summarize, the recommended regulator settings for power-factor corrected urban feeders are:

Beam voltage: 123 volts

Line drop compensation: R = 3 volts, X = 0 volts @ 400 amperes

b. Line Regulator Settings

Rural Feeders normally operate at load levels well below capacity, often being voltage limited. Ties with other feeders are usually limited to the immediate area of the substation. Ties sometimes exist at the extremities, but with very limited emergency capacity.

The lowest acceptable primary voltage at the extremities is around 117 volts equivalent. Beyond such a point, line regulators are required in order to achieve acceptable primary voltage.

On voltage-limited rural feeders, full regulator line drop compensation must be developed at peak load, regardless of normal capacity. See Figure 1 of 2.2.2 C-Appendix for values of "R" compensation to use when normal maximum load current differs from CT rating. Should such a feeder have a tie near the substation and have high emergency loading, special problems will occur in trying to find compensation which will give the desired results at normal load levels and not result in excessive voltages under emergency conditions. No one combination of beam and line drop compensation voltages will work for all feeders.

Settings for line regulators will follow the same general principles as far as beam and compensation settings are concerned. Occasionally a tie with another feeder will occur beyond a line regulator. If in an emergency, load is fed backwards through the regulator, it will attempt to go to full buck or boost depending on the voltage seen by the P.T. In such a case the regulator should be either bypassed or stopped at a setting which will give a fixed voltage boost to this reverse load flow.

All regulators are installed with a special bypass switch to make it easier to put them in or take them out of service. One part of the switch removes a shunt from the series winding when the shunt winding is energized. The reverse takes place when the regulator is bypassed.

c. Special Applications

There are many voltage regulator applications which require special consideration. Most of these applications are adequately covered in references such as the Westinghouse Distribution Systems Reference Book, Chapter 7; and various manufacturers applications literature.

4. BANDWIDTH AND TIME DELAY SETTINGS

Bandwidth and Time Delay settings are necessary in order to avoid excessive regulator operations and "hunting".

Under normal feeder conditions a 3 volt bandwidth and a 45 second time delay will produce good results for both station and line regulators. Where regulators are in series, an additional 15 seconds time delay should be added to each regulator as you go out from the station.

C. <u>APPENDIX</u>

TABLE 1

"R" compensator settings with various C.T. sizes for 3 volts over-compensation

LINE DROP OF 3 VOLTS*
REGULATOR C.T. PRIMARY RATING (AMPERES)

	100	150	200	250	300	400	500
50	6.0	9.0	12.0	15.0	-	-	-
60	5.0	7.5	10.0	12.5	-	-	-
80	3.8	5.6	7.5	9.4	11.3	-	-
100	3.0	4.5	6.0	7.5	9.0	12.0	-
125	2.4	3.6	4.8	6.0	7.2	9.6	12.0
150	2.0	3.0	4.0	5.0	6.0	8.0	10.0
175	-	2.6	3.4	4.3	5.1	6.9	8.6
200	-	2.3	3.0	3.8	4.5	6.0	7.5
225	-	-	2.7	3.3	4.0	5.3	6.7
250		-	2.4	3.0	3.6	4.8	6.0
275	-	-	2.2	2.7	3.3	4.4	5.5
300	-	-	2.0	2.5	3.0	4.0	5.0
325	-	-	-	2.3	2.8	3.7	4.6
350	-	-	-	2.1	2.6	3.4	4.3
400	-	-	-	1.9	2.3	3.0	3.8
450	-	-	-	-	2.0	2.7	3.3
500	-	-	-	-	1.8	2.4	3.0
550	-	-	-	-	-	2.2	2.7
600	-	-	-	-	-	2.0	2.5
650	-	-	-	-	-	-	2.3
700	-	-	-	-	-	-	2.1

*For X volts of line drop - compensation, multiply value from table by X/3.

Normal Maximum Anticipated Feeder Load
Current (Amperes)

C. APPENDIX (cont'd)

TABLE 2
Resistance and Reactance for
Common Construction Types

Copper Conductor Size	ohms/1000 ft. Strands	Resistance, 1/c at 50° C	Reactance, phase to neutral one Conductor, ohms/1000 ft., GMD=31.8"	GMD=39.06"	GMD=59.6"
#6	1	0.4527	0.1430	0.1477	0.1574
#4	1	0.2847	0.1377	0.1424	0.1521
#2	7	0.1826	0.1311	0.1358	0.1455
#1/0	7	0.1150	0.1258	0.1305	0.1401
#2/0	7	0.0911	0.1232	0.1279	0.1375
#3/0	7	0.0723	0.1205	0.1252	0.1348
#4/0	7	0.0574	0.1177	0.1224	0.1320
350 kcmil	19	0.0349	0.1107	0.1154	0.1250
ACSR Conductor					
#2	6/1	.3083	0.1440	0.1487	0.1583
#1/0	6/1	.1992	0.1374	0.1421	0.1517
#3/0	6/1	.1307	0.1307	0.1354	0.1451
336.4 kcmil	18/1	0.0575	0.0711	0.0758	0.0855
556.5 kcmil	18/1	.0349	0.0573	0.0620	0.0716
Aluminum Alloy 6201 (AAAC)					
#4	7	0.5331	0.1364	0.1411	0.1508
#2	7	0.3349	0.1311	0.1358	0.1454
#1/0	7	0.2108	0.1255	0.1302	0.1399
#3/0	7	0.1327	0.1205	0.1252	0.1348
Al. Conductor, Alloy Reinforced, (ACAR)					
343.6	15/4	0.0577	0.1113	0.1160	0.1256
568.3	15/4	0.0378	0.1054	0.1101	0.1197

Note:4 Pin, 9 ft. wood crossarm Construction - GMD = 59.6" Triangular spacing, 35kV side-post Ins; GMD = 31.8" Triangular spacing, Fiberglass bracket; GMD = 31.8" Vertical spacing, 31 inch (preferred) GMD = 39.06"

D. OTHER REFERENCES

17. Distribution Data Book, GET-1008K

18. Distribution Systems, Volume 3, Westinghouse Electric Utility Engineering Reference Books

19. Section 3.8, Distribution Equipment, Regulators, this manual.

2.2.2 FEEDER VOLTAGE REGULATION

A. VOLTAGE REGULATOR APPLICATION

1. SUBSTATION REGULATION

Voltage levels of the power transmission system may vary over a wide range with changes in system load flow. These voltage variations will appear at the distribution substation bus. The customer sees not only this voltage variation, but also variation due to feeder, transformer, secondary and service voltage drop. The sum of these variations may well exceed our established limits (± 5% for most customers) unless some type of correction is applied.

It has been found that in most cases if the feeder source voltage can be properly controlled, satisfactory customer voltage can be maintained.

Controlling the feeder source voltage is accomplished by feeder voltage regulators, or in some cases self regulating (LTC) station transformers. Self regulating station transformers have a built in regulating mechanism. Their only disadvantage is that the regulation can not be applied on an individual feeder basis. This generally is not a great problem where all of the substation feeders have the same characteristics.

2. LINE REGULATION

Line regulators, for the most part, are identical to station regulators except that their current ratings are usually lower. Long feeders may have excessive voltage drop under peak load conditions, making it necessary to place regulators at some point out on the feeder in order to obtain acceptable customer voltage. Application of line regulators follows the same principles as station regulators.

Some single phase line regulators are light enough to be pole mounted. It is sometimes advantageous to mount one regulator on each of three poles for a three phase line. An alternative is a platform, or a mat on the ground.

B. SPECIFICATION OF FEEDER REGULATOR SETTINGS

1. CRITERIA

Feeder regulator settings must satisfy the requirement that the feeder voltage profile be within acceptable limits. This must be true for all likely combinations of load current and power factor.

In addition, it is desirable that:

gg) Large voltage swings over a 24 hour load cycle at any point be minimized wherever possible.

hh) There be a voltage rise in primary voltage on peak (secondary-compensation) to overcome secondary voltage drop.

ii) Feeder voltages not be unnecessarily high, especially at light load. High voltage causes increased transformer core losses due to over-excitation. It also shortens the life of lamp bulbs and some appliances.

jj) Excessive regulator operations be minimized and "hunting" be eliminated through proper selection of bandwidth and time-delay settings.

2. EXPRESS SECTION LINE DROP COMPENSATION SETTINGS

In some cases a feeder will run a significant distance from the substation before reaching the first customer. This portion of the feeder between the substation and the first customer is often called an "express" section. By selecting the proper line-drop compensation settings, voltage may be regulated at the first customer instead of at the regulator output. This is known as express section compensation.

The "first customer" may be defined as the first load served which requires that the primary voltage be kept within certain limits. This restriction is necessary in order that the delivered voltage will be maintained within the Company's established voltage limits. Normally the upper limit will be 126 volts. Feeders having the "first customer" very close to the substation will have no express section and hence will require no express section compensation. The installation of capacitors on the express section of a feeder is to be discouraged. If capacitors are connected to this portion of the feeder it may be necessary to calculate special regulator compensation settings.

In order to establish correct settings for express section compensation, R_1 and X_1, it will be necessary to know the resistance (R_L) and reactance (X_L), of the express section in ohms/phase. The compensation settings may be found by:

$$R_1\,setting = \frac{CT_P\,R_L}{N_{PT}}$$

$$X_1\,setting = \frac{CT_P\,X_L}{N_{PT}}$$

Where CT_P = Primary rating in amperes of regulator current transformer and N_{PT} = Ratio of the regulator potential transformer.

By definition, the "beam voltage" is the setting at which the contact making voltmeter beam will be balanced and will make neither "raise" nor "lower" contacts. The beam voltage differs from the output voltage by the voltage drop in the line drop compensator, taking the P.T. ratio into account. See also Section 3.8, page 3.

Express section compensation is independent of the beam voltage setting. If over-compensation is desired, it must be added to the express compensation. For procedure to request change in compensator setting, see Procedures # 2613.1.

3. BEAM AND LINE DROP COMPENSATOR SETTINGS

These settings must be considered together since they are interdependent. These settings are, however, independent of express section compensation. If there is an express compensated section, just visualize the regulator as being at the load end of this section. Any line drop compensator settings will be added to the express compensation settings to yield the total compensation.

Under this heading we will be dealing with beam volts and volts of compensation as seen by the feeder and referenced to a 120V base. The beam setting may be found by:

$$V_B = \frac{V_{BF}\,N_L}{N_{PT}}$$

Where V_B = Regulator beam setting, V_{BF} = The desired beam voltage, N_L = Line transformer ratio (Primary/Secondary) and N_{PT} = Regulator PT ratio. The following examples are for 13kV and 23kV feeders respectively with standard regulator PT ratios and a 123v beam setting.

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$$V_B = 123v = \frac{123v(7.621kV/120v)}{63.5}$$

$23kV$

$$V_B = 123v = \frac{123v(13.2kV/120v)}{110}$$

a. Substation Regulator Settings

The average feeder is generally less than 25.0 kft. in length. The load center of such a feeder usually lies between 1/2 and 2/3 the total length. Conductor sizes are generally 343T, its equivalent, or larger. Peak loads may be anywhere from 200 to 400 amperes under normal conditions, and can approach 600 amperes during emergency switching. 400 amperes is usually the practical limit for normal loading, and with a fully corrected power factor, the total voltage drop at the end of the feeder usually will not exceed 4 volts. Fixed and switched capacitors are normally applied such that the power factor is reasonably corrected for most load conditions year-round. The uncorrected feeder kvar demand hardly ever exceeds ± 1500 kvar, and on most feeders is much less than this.

In order to prevent excessive voltages during emergency conditions and eventually with load growth, it is recommended that line drop compensation be applied based on 400 amperes. The combination of beam voltage and line drop compensation at 400 amperes should not exceed 126 volts.

A beam setting of 123 volts plus 3 volts of line drop compensation at 400 amperes will achieve excellent results, and satisfy most of the criteria listed in B.1.

It should be noted that a voltage regulator at the substation cannot effectively overcome the excessive voltage drop which will occur on feeders with poor power factor correction. On a 343T feeder with a .90 natural power factor, the voltage drop will be almost double that of the same feeder and kw load with the power factor corrected by proper application of capacitors.

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To summarize, the recommended regulator settings for power-factor corrected urban feeders are:

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b. Line Regulator Settings

Rural Feeders normally operate at load levels well below capacity, often being voltage limited. Ties with other feeders are usually limited to the immediate area of the substation. Ties sometimes exist at the extremities, but with very limited emergency capacity.

The lowest acceptable primary voltage at the extremities is around 117 volts equivalent. Beyond such a point, line regulators are required in order to achieve acceptable primary voltage.

On voltage-limited rural feeders, full regulator line drop compensation must be developed at peak load, regardless of normal capacity. See Figure 1 of 2.2.2 C-Appendix for values of "R" compensation to use when normal maximum load current differs from CT rating. Should such a feeder have a tie near the substation and have high emergency loading, special problems will occur in trying to find compensation which will give the desired results at normal load levels and not result in excessive voltages under emergency conditions. No one combination of beam and line drop compensation voltages will work for all feeders.

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All regulators are installed with a special bypass switch to make it easier to put them in or take them out of service. One part of the switch removes a shunt from the series winding when the shunt winding is energized. The reverse takes place when the regulator is bypassed.

c. Special Applications

There are many voltage regulator applications which require special consideration. Most of these applications are adequately covered in references such as the Westinghouse Distribution Systems Reference Book, Chapter 7; and various manufacturers applications literature.

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Bandwidth and Time Delay settings are necessary in order to avoid excessive regulator operations and "hunting".

Under normal feeder conditions a 3 volt bandwidth and a 45 second time delay will produce good results for both station and line regulators. Where regulators are in series, an additional 15 seconds time delay should be added to each regulator as you go out from the station.

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100	3.0	4.5	6.0	7.5	9.0	12.0	-
125	2.4	3.6	4.8	6.0	7.2	9.6	12.0
150	2.0	3.0	4.0	5.0	6.0	8.0	10.0
175	-	2.6	3.4	4.3	5.1	6.9	8.6
200	-	2.3	3.0	3.8	4.5	6.0	7.5
225	-	-	2.7	3.3	4.0	5.3	6.7
250		-	2.4	3.0	3.6	4.8	6.0
275	-	-	2.2	2.7	3.3	4.4	5.5
300	-	-	2.0	2.5	3.0	4.0	5.0
325	-	-	-	2.3	2.8	3.7	4.6
350	-	-	-	2.1	2.6	3.4	4.3
400	-	-	-	1.9	2.3	3.0	3.8
450	-	-	-	-	2.0	2.7	3.3
500	-	-	-	-	1.8	2.4	3.0
550	-	-	-	-	-	2.2	2.7
600	-	-	-	-	-	2.0	2.5
650	-	-	-	-	-	-	2.3
700	-	-	-	-	-	-	2.1

*For X volts of line drop - compensation, multiply value from table by X/3.

Normal Maximum Anticipated Feeder Load
Current (Amperes)

C. APPENDIX (cont'd)

TABLE 2
Resistance and Reactance for
Common Construction Types

Copper Conductor Size	Strands	Resistance, 1/c ohms/1000 ft. at 50° C	Reactance, phase to neutral one Conductor, ohms/1000 ft., GMD=31.8"	GMD=39.06"	GMD=59.6"
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#4	1	0.2847	0.1377	0.1424	0.1521
#2	7	0.1826	0.1311	0.1358	0.1455
#1/0	7	0.1150	0.1258	0.1305	0.1401
#2/0	7	0.0911	0.1232	0.1279	0.1375
#3/0	7	0.0723	0.1205	0.1252	0.1348
#4/0	7	0.0574	0.1177	0.1224	0.1320
350 kcmil	19	0.0349	0.1107	0.1154	0.1250
ACSR Conductor					
#2	6/1	.3083	0.1440	0.1487	0.1583
#1/0	6/1	.1992	0.1374	0.1421	0.1517
#3/0	6/1	.1307	0.1307	0.1354	0.1451
336.4 kcmil	18/1	0.0575	0.0711	0.0758	0.0855
556.5 kcmil	18/1	.0349	0.0573	0.0620	0.0716
Aluminum Alloy 6201 (AAAC)					
#4	7	0.5331	0.1364	0.1411	0.1508
#2	7	0.3349	0.1311	0.1358	0.1454
#1/0	7	0.2108	0.1255	0.1302	0.1399
#3/0	7	0.1327	0.1205	0.1252	0.1348
Al. Conductor, Alloy Reinforced, (ACAR)					
343.6	15/4	0.0577	0.1113	0.1160	0.1256
568.3	15/4	0.0378	0.1054	0.1101	0.1197

Note:4 Pin, 9 ft. wood crossarm Construction - GMD = 59.6" Triangular spacing, 35kV side-post Ins; GMD = 31.8" Triangular spacing, Fiberglass bracket; GMD = 31.8" Vertical spacing, 31 inch (preferred) GMD = 39.06"

D. OTHER REFERENCES

20. Distribution Data Book, GET-1008K
21. Distribution Systems, Volume 3, Westinghouse Electric Utility Engineering Reference Books
22. Section 3.8, Distribution Equipment, Regulators, this manual.

2.4.1 GROUNDING - GENERAL

Proper system grounding is essential for the protection and safe operation of FPL's distribution system. It fulfills four vital functions:

1. It drains off static charges that might otherwise accumulate.
2. It stabilizes normal operating voltages to ground.
3. It makes possible the prompt and proper operation of relays, breakers and fuses during faults.
4. In conduction with arresters, it protects the system against overvoltages caused by lightning, system faults, and switching.

FPL operates an effectively grounded system. The term "effectively grounded" is defined in the National Electrical Safety Code as "Intentionally connected to earth through a ground connection or connections of sufficiently low impedance and having sufficient current-carrying capacity to prevent the build-up of voltages which may result in undue hazard to connected equipment or to persons."

The NESC recognizes the importance of good grounding, as can be seen from its established set of minimum permissible clearances. For effectively grounded systems, these clearances are based upon phase-to-ground voltage. For systems which are not effectively grounded, clearances are based upon phase-to-phase voltages, and are usually greater than for phase-to-ground voltages.

The industry defines an effectively grounded system as one on which the ratio X_0/X_1 falls between 0 and +3.0 and the ratio R_0/X_1 falls between 0 and +1.0, where, in symmetrical component notation, X_0 and R_0 are zero sequence reactance and resistance, respectively, and X_1 is positive sequence reactance.

FPL uses a performance type of definition; that is, during a ground fault to one phase, the voltage to ground on the other two phases will not exceed 135% of normal.

FPL also conforms to the National Electrical Safety Code definition, both as to quality and as to the number of grounds on its common neutral system. None of the requirements established by the Code for this type of system should be violated.

Lightning and switching surges can cause overvoltages to exist on a distribution system. To protect FPL's system against these overvoltages, arresters are installed on all three phases at prescribed intervals along the line. The ground leads from each arrester station are connected to low-resistance grounds.

If the ground resistance is not low enough, surges will not be completely discharged to ground and will remain on the line longer, subjecting the arresters to energy levels in excess of their rating. In time, the arrester protection system will deteriorate prematurely to the point of damaging the arrester stations, thereby affecting service reliability. Past engineering studies have shown that ground resistances of 25 ohms or less have a greater ability to discharge surges to ground. At transformer installations, the better the transformer ground with respect to the customer's ground(s), the more protected are the transformer and load from secondary surge overvoltage effects. Consequently, low ground resistances will improve the performance of FPL's surge protection system.

With an effectively grounded system, overvoltages during line to ground faults are limited to 135% of the operating voltage on the unfaulted phase(s). Recent investigations have confirmed that system overvoltages of 168% of the operating voltage during system faults can be expected on wye-grounded distribution circuits operating with insufficient grounding, resulting in failed arresters. Hence, an effectively grounded system provides FPL with lower material and equipment costs, since low insulation and arrester ratings capable of sustaining a maximum of 135% overvoltage can be utilized for the construction of distribution lines.

FPL has joint use contracts with most of the telephone companies in its territory. The telephone companies are encouraged to connect their grounding system to our ground so that normally there will be only one ground potential on the pole. If they request permission to bond their facilities to one of our isolated system grounds, they should be asked to furnish complete information covering their system which is to be bonded and the reason for their request. An analysis should be made of the particular situation. Permission to bond may be given, if the analysis is favorable to bonding.

2.4.2 GROUNDING OVERHEAD LINES

A. PRIMARY LINES

FPL's primary distribution system is a multigrounded wye system. In such a system, there is a continuous neutral conductor, which is solidly grounded at various points as shown in Figure 1. The neutral conductor is sized so that the system meets the industry definition of an effectively grounded system, as defined in Section 2.4.1, page 1. Close adherence to the principles of good grounding produces a system which has a high degree of safety for personnel and equipment. Whenever a fault occurs, relaying will be prompt and reliable.

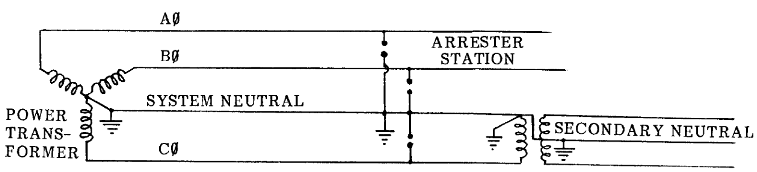


Figure 1

On three phase lines with balanced loads, the neutral normally carries little or no current. During single phase switching, unbalanced loads or fault conditions, the neutral does carry substantial currents. The earth will share this current through the neutral ground ties, and will minimize primary voltage unbalance. With FPL's grounded neutral system, the voltage to ground on the unfaulted phases should not exceed 135% of normal during a fault.

On single phase lines in rural areas, grounding connections to the neutral put the earth in parallel with the neutral. This causes the earth to carry a share of the neutral current, reducing voltage drop and losses.

For best protection of our system, the surge arrester ground, the primary neutral and the secondary neutral are interconnected. The National Electrical Safety Code permits such interconnection if the secondary neutral has at least four (4) ground connections in each mile of line in addition to a ground connection at each individual service and in addition to the direct earth grounding connection of the arrester.

At the substation, the neutral is grounded, usually through a 0.8 ohm neutral reactor which is used to limit phase-to-ground fault currents to a manageable size. Driven grounds are installed at all surge arrester stations, which are spaced along the feeder at intervals specified in Table I, Section 2.9.1 of this manual. In addition, grounds are required wherever arresters are installed for equipment protection. The cases and tanks of line equipment are also grounded to the system neutral, as is described later in this section.

The grounding connections referred to herein are "driven grounds", which are made up of 5' or 10' sections of 5/8 inch copperclad rod. As each section is driven, another is coupled to it until the rod reaches permanently moist earth. The resistance of the driven ground is measured according to the procedure given in DCS, Section G. As this standard now states, the maximum permissible resistance is 25 ohms; further reduction to 10 ohms is desirable, if this can be accomplished without using more than 40 feet of rods in tandem.

Deep driven rods is the preferred method, but where rock or other soil conditions make it impossible to drive rods deep enough to measure 25 ohms or less resistance, it is sometimes necessary to "cluster" the ground rods; that is, to drive several sets of rods and connect them in parallel to obtain a satisfactory ground. The NESC rules require that the rods in the cluster be separated by at least six feet; however, FPL policy requires that they be separated by a distance equal to or greater than their driven depth. Ground rods may also be driven at an angle, up to 45°, to increase by approximately 40% the length of rod in the earth.

As an acceptable alternative to driven grounds in URD areas, a bare #4C wire may be laid along the open trench when conduit and cable are being installed. This wire, known as a counterpoise, should have an overall length of at least 300 ft.

See DCS, Section G for installation details on all of these grounding methods.

Metallic water pipes or well casings make excellent grounds, and the NESC states that they are the preferred grounding electrode where available. However, their availability is limited, since many water lines are now constructed with PVC and other non-metallic materials.

The grounding conductor must always be capable of carrying any current which may be imposed upon it long enough for a fuse to blow or a breaker to open. A #6 copper conductor is adequate for the connection from overhead lines to the driven grounds described above. Low resistance in all grounds and their connecting leads is extremely important in providing surge protection. For additional information on lightning surges, see Section 2.9.1, this manual.

In addition to driven grounds, it had been the practice at FPL to install at every pole (except service poles) a pole bond consisting of a #6 copper conductor run all the way down the pole to a butt-wrap or butt-plate. The intent, of course, was to add to the grounding provided by driven grounds, and insure that "grounded" hardware on the pole was actually at ground potential. In recent past, it was established that in some locations these pole bond/butt wraps added very little to the effectiveness of the grounding system, and that their cost could more effectively be spent on decreasing the spacing between surge arrester stations. Therefore, they are no longer installed. Pole bond wires on new installations will be extended above or below the neutral only far enough to connect to the driven grounds and to permit bonding of transformer tanks, street light brackets, and such hardware. In salt spray areas or wherever hardware is bonded, it will be adequate to bond to the system neutral.

For further information on pole grounds, see Section 4.2.3.

In some locations, lines are protected by overhead ground wires instead of surge arresters. This is an alternate standard construction used in areas where direct lightning stroke activity is prominent. (See discussion of this subject in Section 2.9.1.) Low resistance grounds connected to the pole grounds at every pole are a vital part of this protection scheme. The ground wire shall be supported out from the pole on stand-off insulators where it passes through the primary space. This is done in order to maintain the insulation level of the primary.

B. SECONDARY LINES

Secondary lines are grounded at the transformer supplying the secondary. For single phase, three wire 240 volt systems, and for 4 wire, 3 phase 240 volt delta systems, the grounded neutral is connected to the center tap of the winding supplying the lighting load. On 4 wire, 3 phase wye systems, the grounded neutral is connected to the wye point. For situations involving other voltages, see DCS I-53.1.1 and I-53.1.2.

Proper grounding will aid in the protection of the secondary and customers service from:

5.Surges, especially lightning;

6.Static voltages;

7.The intrusion of primary voltages;

8.Unbalanced currents caused by broken conductors.

Grounding is especially important in protecting 120 volt equipment connected across each half of the 240 volt secondary of the transformer. It holds the neutral at a point halfway between the two 240 volt conductors. (See Figure 2a.) Without grounding, if the customer's neutral became isolated from the transformer neutral point, unbalanced voltages across the equipment would result. The voltages across the equipment would split in proportion to the impedance of the load on each side of the circuit. Burned-out light bulbs and damage to appliances might result. Note in Fig. 2b that with as little as 1 ohm resistance in the earth (ground return path), each "leg"-to-ground at the customer's service experiences a 12% change in voltage. As the ground resistance increases at the transformers pole this voltage change will become greater. If the ground resistance were to be infinity, there would be no return path to the transformer through the neutral or earth and the current which flows will pass through both 120 volt loads in series. This will create the worst unbalance condition and in Figure 2b each 120 volt load will have 9.6 amperes of current flowing through it which will cause the 20 ohm load to have 192 volts across it. This would burn out light bulbs, radios and other equipment.

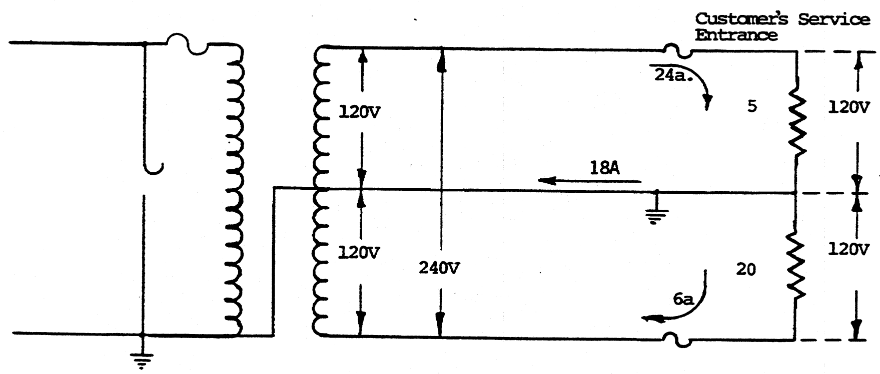


Fig. 2a – NORMAL CIRCUIT-NEUTRAL INTACT
3 WIRE, 120/240 VOLT SERVICE

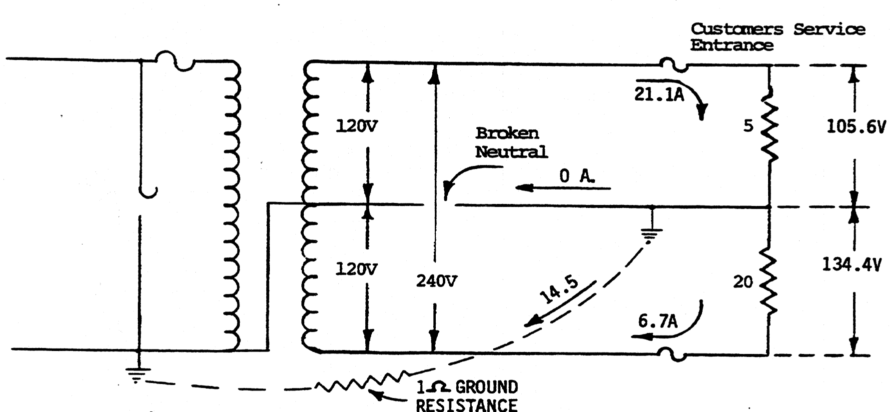


Fig. 2b – ABNORMAL CIRCUIT-NEUTRAL OPEN

Secondary grounding conductors must also be able to carry the current imposed on them by a fault until it is cleared by the operation of a fuse or breaker. Fuse sizes and breaker settings are usually higher on secondary systems than on primary systems, so you may need to use larger grounding conductors on secondary. The neutrals on three and four wire secondary systems normally carry only the unbalanced current. They must still be able to carry, from a thermal standpoint, the unbalanced current that would result from a blown customer's fuse, an open secondary phase conductor or improper load distribution. Since the phase conductors are often sized based on voltage drop considerations rather than on thermal considerations, the neutral may often be at least one size smaller than the phase conductors. However, it must be able to safely carry fault currents long enough for a fuse to blow or a breaker to open.

C. EQUIPMENT GROUNDS

Grounds are connected to the cases and tanks of equipment to limit voltages which might appear on the cases due to insulation failure inside the equipment. In many instances, circuit grounds and surge protective grounds will also be installed at equipment locations. When a voltage is impressed between a ground rod and remote earth, current flows and a voltage gradient is established between the rod and remote earth. About half of the total voltage drop will appear across the first two feet of the earth adjacent to the ground rod. A person standing on the earth two feet from and touching a grounded metallic object may be subjected to this voltage, if any. This is known as "touch" voltage or "touch" potential. The same person, if his feet were separated, would be subject to a voltage between his two feet. This is known as "step" voltage or "step" potential.

1. Transformer Banks

The standard overhead transformer on the FPL system is one that is connected from phase to neutral. Most of them have two primary bushings. There are, however, a large number that have only one primary bushing. On these, the other connection to the primary winding is made inside the tank, to the tank wall. In both types, the tank is connected to the neutral side of the transformer winding, and if disconnected from neutral and ground, would be energized at primary voltage through the transformer winding. It is therefore FPL's practice to provide two paths from the tank to the system neutral. This practice is also followed with two bushing transformers since the neutral bushing is connected to the secondary neutral which is grounded to the case. This practice assures that the case will have no dangerous voltages on it.

At each transformer station, the primary system neutral and secondary neutral are common and are interconnected with the surge arrester ground. The distance along the conductor in the surge current path from the point on the primary where the surge arrester is connected to the point where the tank or secondary neutral is connected should be kept as short as possible. The rapid rate of change of the surge current, di/dt, multiplied by the inductance, L, of a straight piece of wire can create a voltage as high as 8 kV per foot of ground lead. The surge voltage impressed across the transformer insulation would thus be the discharge voltage of the arrester plus 8 kV per foot of the total length of conductor used to connect the surge arrester into the circuit.

2. Capacitor Banks

The tanks and the primary neutral of capacitor banks are grounded to a low resistance ground and interconnected with the system neutral and the surge arrester ground. Some harmonic voltage usually exists between line and ground. This will cause some harmonic current to flow in the neutral ground lead. Ground connections must be completed before the bank is energized. A driven ground of 25 ohm or less will normally accommodate the harmonic current without causing telephone interference. FPL has an obligation to keep interference caused by FPL equipment to a level that modern telephone equipment can tolerate.

3. Reclosers and Sectionalizers

Recloser and sectionalizer tanks must be grounded and interconnected with the surge arrester ground.

4. Street/Outdoor Lighting Brackets

Street/outdoor lighting brackets should be grounded to the system neutral. If the system neutral is not present, it should be extended, if practicable. If not practicable to extend the system neutral, a driven ground must be installed at each light location.

Where a street light or outdoor light is installed on a service pole or a terminal end pole, a driven ground is not required. For OH and URD series street light circuits all poles should be grounded with a driven ground rod. Metal poles and concrete poles shall be grounded with driven ground rods at every pole. All other street light circuits must have a minimum of four driven grounds per mile.

5. Regulator Stations

Regulator tanks must be grounded and interconnected with the system neutral and the surge arrester ground. Since the shunt coil in the regulator performs the same function as the primary of a transformer, its neutral bushing must also have two connections to the system neutral. See C1.

6. Service Entrance Equipment; Meter Sockets and Cabinets

The service entrance conduit, the meter socket or cabinet and the service switch are installed by the customer, and all must be grounded by the customer's electrician, in accordance with the local code.

7. Secondaries of Instrument Transformers

The secondaries of instrument transformers must be grounded except where the functional requirements of the circuits do not permit them to be grounded. Secondary circuits, except for very short lengths, when in a primary area where primary voltage exceeds 600 volts, must be protected by grounded conduit, or other grounded metallic covering.

8. Fences and Gates

All fences and gates maintained by the Florida Department of Transportation crossed by FPL overhead lines of any voltage must be grounded. See DCS, Section G for method of grounding.

2.4.3 GROUNDING UNDERGROUND SYSTEMS

A. UNDERGROUND SYSTEMS GENERAL

All non-energized metal parts in underground electrical installations must be grounded to suitable grounding systems. Such parts include metal tanks and cabinets, equipment mounting frames, metal conduit installations, metallic cable sheaths, metallic riser conduits, surge arrester leads, etc.

Two general types of grounding are encountered on underground systems; 1) system neutral grounding and 2) isolated grounding. All cable sheaths and equipment without cathodic protection are tied to the system neutral and grounded using a copperweld ground rod. Cables and equipment requiring cathodic protection, have been generally connected to isolated grounds. These isolated grounds typically have separate galvanized ground rods, and zinc anodes, attached to the lead cable sheath. Changes are underway to modify most of our Distribution "isolated ground" systems. Paper Insulated Lead Covered (PILC) cable is now being bonded to the system neutral at substations, riser poles, manholes, and vaults. Anodes at these locations will continue to be maintained, however.

On another note, the Miami airport, downtown Miami Network, and Armored PILC submarine cables, will retain their isolated grounding systems. They should continue to be maintained.

It is essential that the metallic sheath of cables be grounded only in vaults and manholes, and if direct buried, only at terminations and switches. Voltages are induced in the sheath of single conductor cables by the current they carry. If the sheath resistance is low, and there are multiple grounds on the sheath, large circulating currents may occur when the cable is loaded. This increases losses, heats up the cable and lowers its ampacity.

The size of a grounding conductor should be in accordance with sheets G-6.0.0 and G-12.0.1 in the Distribution Standards. The minimum size grounding conductor for circuits and equipment should generally be #6 copper, except that #12 copper may be used to ground instrument transformer secondaries. If a grounding conductor is the only conductor running through a metallic conduit, it should be bonded to the conduit at each end.

B. CABLE IN DUCT AND MANHOLE SYSTEMS

Many primary cables in duct and manhole systems are still lead sheathed. This lead sheath is part of the neutral system. It is typically supplemented by one or more #4/0 copper conductors, laid on top of the duct bank. Cable sheaths entering or leaving a vault or manhole are connected to a ground bus at the duct face. The ground bus should be connected to a driven ground rod, the system neutral, and an anode. (See Distribution Standards, sheets G-4.0.1 through G-7.0.2 for manhole and vault grounding instructions.

Lead cable sheaths are protected from corrosion by a polyethylene jacket. To prevent electrolytic corrosion resulting in a hole in the jacket, the lead sheaths of cables must be connected to an anode. This anode is intended to work as a sacrificial element and must be replaced when necessary.

In the past, many feeders leaving a substation bus had cathodic protection, in the form of polarization cells. As the feeders were converted to "system neutral" grounding, these polarization cells were shorted out by having their isolated bond ring tied to the substation ground grid. The cell was then removed. See section 2.7.1 of the DERM for more information on cathodic protection.

Sometimes, lead covered cables are terminated at overhead primary riser poles. In the past, if cathodic protection was needed, the lead sheaths were connected to an isolated ground. Surge arrester ground leads and the metallic riser conduit were also connected to the same isolated ground. The isolated ground lead was insulated and kept separated from the bare pole bond connected to the system neutral. Our present policy is to connect these items (lead sheaths, arresters, galvanized ground rod, etc.) to the system neutral. In addition, a copperweld ground rod will be driven and secured at the location. See DCS G 9.0.2 for details.

If the lead-sheathed cable did not have cathodic protection, its sheath was already grounded to the system neutral ground. This also holds true for submarine cable, with an exterior corrugated copper tube for its sheath and neutral.

C. CABLES AND EQUIPMENT IN BURIED CONDUIT SYSTEMS

FPL's buried, cable in conduit, primary system normally uses PVC conduit, aluminum conductor, crosslinked polyethylene insulated cable with a copper concentric neutral and an outer insulating polyethylene jacket. The neutral is interconnected with the driven ground and the secondary neutral at each transformer station. With cable in conduit systems, it is very important that standard grounding practices and ohm resistance levels are used at both the sending (riser pole) and receiving (transformer) ends. These systems don't have good contact with earth except at those ends. Feeder cables leaving substations require riser pole surge arresters at each overhead termination. The concentric neutral should be connected to the system neutral at each end.

The neutral of a secondary and service cable in conduit should be grounded at the transformer and at the customer's service entrance.

Pad mounted transformers and switches are grounded to the system neutral and to driven grounds. Surge arresters inside these devices must be grounded to the system neutral.

D. CABLES AND EQUIPMENT IN HIGH-RISE BUILDINGS

The customer is required to furnish a bonding conductor to tie each of the secondary neutrals together, to a water pipe ground, and to our system neutral in the main vault.

FPL also carries an insulated bonding wire to each vault. It connects to the secondary neutral, the transformer case and one terminal of a secondary arrester (if present) in each stacked vault and to the system neutral in the main vault.

The concentric neutrals of the primary cables connect in each vault to the primary neutral bushing of the transformer, the primary neutrals of the alternate primary cable, the cable tap, and the other side of the secondary arrester, if present. They are to be connected to the system neutral in the main vault.

If the building has thirty or more floors, a separate bonding of #2 bonding wire must be made in the top vault to a water pipe ground.

Primary and secondary surge arresters are provided only in the three upper vaults for 7.6/13.2 kV circuits. They are provided in all vaults for 13.2/22.9 kV circuits. The purpose of the secondary arresters is to tie the primary and secondary neutrals together during lightning surges, while keeping them isolated during normal operation.

2.4.4 GROUNDING REFERENCES

9. IEEE standard 142-1972, "IEEE Recommended Practice for Grounding of Industrial and Commercial Power Systems."

10. ANSI C1-1999, "National Electrical Code," (NFPA-70, 1993).

11. IEEE Standard 80-1961 (R 1971), "Guide for Safety in Alternating-Current Substations."

12. ANSI C2, 1997 Edition, "National Electrical Safety Code."

13. EEI Publication No. 55-16, "Underground Systems Reference Book," published 1957.

14. "Electrical Transmission and Distribution Reference Book," by Westinghouse Electric Corp., 1950.

15. FPL Distribution Construction Standards, Section "G".

2.5.1 CABLE AMPACITY

A. GENERAL

The ampacity (current carrying capacity) of an insulated cable is determined by the type of cable insulation, the heat generated within the cable, and the rate of heat transfer from the cable to the surrounding medium. Heat within the cable is the result of I^2R losses in the conductor, dielectric losses, shield losses (including concentric neutral losses) and in some cases, heat transferred into the cable from the surrounding medium. Heat transfer is a function of the thermal conductivity of the insulation, cable coverings, and the surrounding medium, as well as the temperature difference between the conductor and the medium.

In some cases, ampacity is limited by the maximum permissible operating temperature of the cable insulation. In other cases, especially in direct buried cables, the limitation is the interface temperature between the cable and the surrounding medium.

If other cables are contained in the medium adjacent to the cable being studied, the temperature differential between the medium and the cable conductor will be affected.

It can be seen from the above that there are a large number of independent variables which affect the cable ampacity. For this reason, manual calculations become very tedious, or nearly impossible if all operating conditions are to be covered. Computer programs are used for these calculations.

B. FPL AMPACITY TABLES

The ampacity tables for primary cables are included in the Distribution Construction Standard (DCS) UV-15 and for the secondary cables in UV-17.

It is believed that UV-15 and UV-17 will satisfy the majority of the needs for cable ampacity figures. Should additional ampacity data be required, contact the FPL Distribution Product Engineer for cable. Information is available at the Distribution Reliability Web Site.

C. DETAILS TO INCLUDE IN REQUEST FOR CABLE AMPACITY

In requesting ampacities for cables or conditions not included in FPL Ampacity Tables certain details must be furnished. These concern cable construction, installation details and details of the surrounding medium.

1. Construction Details

Description and/or M&S number of Cable. If description only, include general type of cable, conductor material (AL or CU), number of conductors (1/C, 3/C or 3-1/C triplexed), size of conductor, type of insulation and insulation thickness, type of insulation shield, sheath and jacket material and the thickness and the cable overall outside diameter.

2. Cable Installation Details

State whether cable will be in direct buried duct or in concrete encased duct bank. If submarine cable, state whether it is laid loosely on bottom or trenched in. Burial depth should also be specified.

3. Details of Surrounding Medium

State if summer or winter ampacity is needed, whether soil is wet or dry, load factor (if known) and number and location of other cables installed adjacent to the cable being studied. If submarine cable, is it trenched into sand, or organic silt?

D. USING THE FPL AMPACITY TABLES

Before using the ampacity tables in DCS UV-15 and UV-17, read sheets 1 and 2 of UV-15 carefully, so that the most appropriate ampacity value for the cable is selected.

If you have two cable circuits in a duct bank and each circuit is equally loaded, the ampacity of each circuit is reduced. Should one circuit fail and be taken out of service, the ampacity of the remaining cable circuit increases to the one cable per duct bank rating. This would also be true if one circuit is a spare and not normally loaded except when its companion (in the same duct bank) fails.

In some cases where long submarine cables are involved, it may be economical to use a reduced kcmil size cable in the water, matching ampacity to a larger kcmil size cable in the terminal risers at each end.

E. OTHER REFERENCES

33. AIEE - IPCEA Power Cable Ampacities, American Institute of Electrical Engineers, 1962
Volume 1 - Copper - AIEE Pub. No. S-135-1
Volume 2 - Aluminum - AIEE Pub. No. S-135-2

34. J. H. Neher & M. H. McGrath," The Calculation of Temperature Rise and Load Capability of Cable Systems", AIEE Transactions, Part III, Vol. 76, October, 1957, pp. 752-772.

35. IEEE Standard 835, 1994, “IEEE Standard Power Cable Ampacity Tables”.

36. Anders, G.J., “Rating of Power Cables: Ampacity Computations for Transmission, Distribution, and Industrial Applications”, Ontario Hydro Technologies, published by IEEE.

2.6.1 ASSET MANAGEMENT SYSTEM – AMS (FORMERLY DISTRIBUTION DATA BASE - DDBS)

A. GENERAL

The objective of this section of the Distribution Engineering Reference Manual is to give engineers, designers, planners and other users a basic overview of what AMS is, and how it can help them perform their job more effectively and efficiently.

The Asset Management System (AMS) is designed to provide the user with an effective way of monitoring the FPL Electrical Distribution system. These distribution facilities are registered to an accurate GIS Landbase in a graphical format. The information contained in this system can be accessed by users with an application known as the AMS Web Query Tool. This tool can be launched from any Windows based PC connected to FPL's Intranet using Internet Explorer. The FPL AMS web site has valuable links to various training and reference materials you can refer to as needed.

Basic functionality of AMS:

- The central repository of all Distribution Facility Data.
- Display distribution facilities and their attributes in relationship to land features in the form of a map.
- Query distribution objects in the database for specific information.
- Perform traces of overhead and underground facilities such as tracing a feeder from a substation to a switch.
- Check transformer information (including location, size, type, operating kv, loading, interruption, and maintenance), and lateral information (including fuse size, type, loop information, and lateral loading).

B. AMS MAPPING PRODUCTS

There are four mapping products available in AMS. The maps are generated from the AMS data stores using the AMS Web Query Tool under the "Maps" tab and can be selected as follows:

- Primary Map - These show all overhead and underground primary distribution facilities.
- Feeder Map - These are essentially a primary map without lateral conductors and devices.
- Circuit Packet – These are map packages consisting of a cover sheet along with all of the associated primary maps for a specific feeder. When a circuit map package is printed, the individual primary maps are colored in such a way as to allow a user to easily identify the selected feeder. All of the electrical facilities located on opposing feeders are displayed in yellow. When printed in black and white, this color combination allows the user to distinguish the selected feeder simply by the grey scales.
- Key Sheet – These show a list of all map numbers by Service Center. They can be helpful to locate specific maps.

AMS maps are numbered using a uniform statewide numbering system derived from a combination of letters and numbers. For example: map number AG 0397. Letters A to ZZ from east to west and 0001 to 9999 from south to north. The map boundaries have been defined so that adjacent maps align when assembled. Maps are created in 3 different scales, 1"=100, 1"=300 and 1"=600, based on the density of the facilities in the area. Maps are generated automatically from a "Primary View" within AMS. Each time a device is updated the effected map product will be refreshed with an updated copy ready to be viewed or printed. Map data is refreshed on a nightly basis.

C. TRANSFORMER LOAD MANAGEMENT

Because of the different types of customers and the diversity associated with their usage, it is an accepted fact that customers' loads do not all peak at the same time. By the same token, with the restricted number and types of customers associated to any transformer, it follows that not all transformers will peak at the same time.

In order to achieve a desirable loading situation within AMS, it is necessary to know or closely estimate the load each transformer is carrying. Since there are over 680,000 distribution transformers within the Florida Power and Light territory, each reaching peaks at various times, a formula was developed to calculate the loading of transformers based on seasonal peak usage.

This load calculation process is done nightly, based on meter readings received each day. If additional load is to be added to an existing transformer, the user should use the AMS Web Tool to access the present peak readings, and then add the expected additional load to the transformer, thus verifying if the transformer is of adequate size or if the size needs to be increased.

Load calculations are kept for a period of 5 seasons, the current season, and the previous 2 years. The displayed loading can also be corrected if found to be inaccurate (i.e. meter reading error, or customer mis-association).

D. TRANSFORMER LOAD MANAGEMENT REPORTING

Although the load calculation is a process initiated by the meter reading process, there is a need to retrieve pertinent information from this process. AMS allows various ways to retrieve information using various reports. These reports can be accessed through the AMS Web Tools link to the Data Warehouse Reporting tools. The information produced from these reports is updated on a weekly basis from data received from AMS.

It is important to remember that transformer loading is based on averages, and not all transformers will conform to these averages. Determining the actual loading on some transformers will require the application of engineering judgement, especially on open-delta banks.

E. LATERAL LOADING

The loading of laterals can also be determined based on the accumulated kva of the transformers associated to the lateral. Reports are also produced based on the lateral loading.

F. AMS UPDATES - WORK ORDER AND DATABASE CHANGES

TRS is responsible for the maintenance of AMS and the Primary Map products and they have the final responsibility of inputting all updates to the AMS system using an application commonly referred to as an AMS Update Seat. The only exception to this is the maintenance of Substations and Feeder Heads which are maintained by the Planning group.

Updating of the AMS system is accomplished through standard “Work Order” updates or “Database” changes using an AMS update seat. The designer of a job can request updates by the Technical Resource Services (TRS) department to update information affecting AMS. These updates will then be passed to a central database that feeds the Data Warehouse system. Updates involving an existing Work Order in WMS are accomplished via an AMS Work Order and miscellaneous updates are done via an AMS Database change.

AMS Work Orders will contain the additions, deletions, or changes that the job will make within AMS. The Work Order is initially placed in AMS in the “In Construction” status. Objects for that job will then appear within the AMS Web Query Tool in a status of “Propose Install” (Magenta). When the job is near completion, the Work Order is then promoted to the Constructed status (Blue) in AMS and will update what is viewable in the AMS Web Query Tool overnight.

G. LINE SECTION DATA (FEEDER INFORMATION) GENERAL

The FPL distribution system is large and complex, constantly changing and expanding. In order to insure reasonably reliable service to its customers, the planning and operational personnel needs to retrieve data from the AMS system in a manageable form. This information can be found and downloaded from AMS utilizing one of several reporting tools. One tool within AMS is the Load Between Switches Report. Others such as Open Switch Report, Feeder Ties, Lateral Load, Unassociated Customers can be accessed using the Data Warehouse reports option.

H. FEEDER ANALYSIS

AMS provides various reports on line for use by the reliability planning group. Information provided by AMS can also be captured and then downloaded to PC's for feeder analysis through reports such as "Load Between Switches" enabling the planner to perform analysis on a feeder with both current and future loads.

I. UPDATING FEEDER INFORMATION

AMS allows the installation or deletion of feeder devices, line-sections, and sub-stations through the same updating process explained earlier with transformers and laterals. However, any job concerning the installation or removal of substation information must be closely coordinated between planning and TRS, to ensure the integrity of AMS.

J. USE OF AMS BY TROUBLE OFFICE

Information produced by the AMS system is valuable to the trouble department and the Trouble Call Management System (TCMSII) in handling interruptions. The use of the AMS system helps the trouble office determine the type of outage, and provides that information to field personnel, thus providing more efficient service restoration to the customer.

K. USE OF AMS BY DESIGNERS

To obtain the most benefit from the AMS system as an aid in everyday work, the designer should become familiar with AMS options. A few pertinent items are listed below that a designer should know in order to perform daily functions efficiently and effectively.

37. If the system is to be useful, it must have the confidence of its users. It must be kept current and up to date.

If errors are found in the field, it is the designer's responsibility to make sure that AMS is corrected as soon as possible by contacting the TRS department.

38. Some transformers are overloaded or underloaded for special reasons. Once it is determined that the loading is correct, a new 'LOAD CODE' should be assigned to prevent the transformer from appearing on exception reports.
39. If additional loading is to be entered on the transformer or lateral, verify that the device is not already overloaded. If it is already overloaded, or an overload is expected with the additional load, make the necessary changes in the job to alleviate the problem.
40. When installing additional transformers, determine whether the new load may be added to the existing lateral or if a new lateral is needed and proper phase balance is maintained.
41. Let's all do our part in keeping the AMS system current and accurate. By doing this the integrity of the system will be maintained.

2.7 CORROSION CONTROL - GENERAL

GENERAL

FPL has many millions of dollars of distribution equipment installed in outdoor locations where it is subjected to the elements. Much of this equipment is made of metal and may rust or otherwise deteriorate unless it is protected. Economic necessity makes it imperative that we adequately protect our equipment to realize an actual service life equal or greater than the book depreciation life. In general, we will refer to rusting, loss of metal or other deterioration of the metal itself as "corrosion". The severity of conditions causing corrosion vary, depending on where the equipment is located. Equipment on poles may corrode less than the same equipment pad mounted at ground level. Pad mounted equipment may corrode less than the same equipment would if used in underground vaults or directly buried. This may give us a clue to what causes most corrosion; namely, moisture. Any of the common metals, if kept perfectly dry, will not corrode.

Metals which are not in contact with the earth or bodies of water can usually be protected by a moisture excluding coating, such as paint. Metals buried in the moist earth, or submerged in water may need additional protection besides the coating.

This discussion will be in two parts. One part will deal with the basic cause of corrosion, and the methods and equipment for reducing corrosion of underground cable and other equipment. This method is known as Cathodic Protection. The other part will deal with paints and coatings, useful both on overhead and underground equipment.

2.7.1 CORROSION CONTROL - CATHODIC PROTECTION

A. CAUSE OF CORROSION

You are familiar with the ordinary flashlight battery. You have observed that when you slip it into the flashlight case, a center terminal on one end contacts one terminal of the light bulb and the exposed bottom of the battery case is contacted by a spring when the case is screwed closed. In this state, the flashlight is producing no light and the battery will last a long time. Though installed, it is open-circuited. However, when the switch is moved to the "On" position, the light comes on, and if left "On", the battery will go "dead" after a while.

The battery is constructed of a zinc can, open at the top and filled with a moist pasty chemical electrolyte. A carbon rod is immersed in the electrolyte. The rod is kept from contacting the can by spacers and an insulator at the top. A metal cap covers the top of the carbon rod; this is the positive terminal. The negative terminal is the bottom of the zinc can, which is left uncovered so that contact can be made.

When the flashlight is turned on, current flows from the positive terminal, through the filament of the bulb and the rest of the flashlight circuit to the negative terminal. Current leaves the positive terminal in the exterior circuit and is received by the negative terminal. To complete the circuit, current flowing through the electrolyte inside the battery must leave the negative terminal (the zinc case) and be received by the positive terminal (the carbon rod). When the current flows from the zinc into the electrolyte, it carries particles of zinc with it which move through the electrolyte in the form of ions to the carbon rod. Here they give up their positive charge to the carbon rod and the zinc combines with the chemical to form a compound. As zinc is lost from the case, we may say it corrodes. If the light is left on, the case corrodes away until little zinc is left. Little or no current is generated and the battery is "dead". The battery also will become dead if the case is broken open and the electrolyte dries out. The electrolyte must be moist for the battery action to take place.

What is the driving force behind this current flow which corrodes away the zinc?

Let us bury a number of the different metals commonly used in distribution systems in moist soil. If we then measure the voltage between any two metals, we will get different readings, depending on what combinations we select. Metals we commonly use are copper, lead, galvanized pipe, cast iron, aluminum, new uncoated steel pipe, and rusty steel pipe. Our measurements will show that the copper is positive with respect to all the other metals named.

If we compare the combination of the copper and any of the other metals buried in the soil to our flashlight battery, the action that takes place can be traced. The copper takes the place of the carbon rod; the soil is the electrolyte and the other metal takes the place of the zinc can. The "driving force" is the voltage measured between the two metals; in the battery, it was between zinc and carbon.

To start the battery action, there must be a metallic connection, such as when we ground a galvanized anchor rod to a copper clad ground rod. When the circuit is thus completed, current flows from the copper through the metallic circuit to the anchor rod. However, in the soil electrolyte, current flows away from the anchor rod and flows through the soil to the copper. This takes particles of the zinc galvanizing from the rod and we say it corrodes. The metallic connection in the above case is above ground; it could have been casual or intentional contact between the copper and the other metal in the soil and the result would be the same. The amount of current flow and consequently the rate of corrosion depends on the circuit constants; that is, the voltage and the circuit resistance. The soil resistance depends on the amount of moisture in the soil and its chemical content. If two metals which have a large voltage difference are buried in wet highly conductive soil, the more negative metal will corrode quickly.

Tables are available from which one can obtain the voltage (potential) difference between different metals in an electrolyte. These tables would be very voluminous if they had to list the potentials between any combination of two of all the existing metals. Instead, the tables usually list the potential of each metal to a reference. Then, by addition or subtraction, the difference in potential between any two of the metals can be obtained. Table I shows common metals arranged in galvanic series order. Also shown, is their approximate voltage to a common reference point, which is a copper-copper sulfate reference electrode. Their consumption rate in pounds per ampere of galvanic current per year is also shown, where available. The metals at the top of the list are more negative and will be corroded if paired with a metal lower in the list. The greater the separation in the list, the more the voltage will be between the two metals, and the more severe the corrosion.

Table II is also furnished to give the galvanic series in sea water. The positions of a few metals in this series are reversed from the ones used for common soils.

Using Table I, we see that the voltage for carbon is + 0.3 volts, while that for zinc is - 1.1. The voltage between our battery terminals should thus be 0.3 + 1.1 = 1.4 volts. We know it is actually closer to 1.5 volts. However, the electrolyte is different, and the second decimal was dropped in making the approximate readings, so this is a satisfactory correlation.

In working with cathodic protection, situations are not as nice and clean cut as the above would indicate.

Different surface conditions on a given metal can cause adjacent areas of the metal to have different galvanic potentials. Since the metallic connection is inherent in the body of the metal, the difference in potential will cause local corrosion if electrolyte conditions are right. This type of situation could be set up by a pipe wrench scraping the outer surface of a pipe. This would leave a clean, bright area next to a dirty area covered with oxides, etc. A local corrosion "cell" could be set up if moisture is present.

TABLE I - GALVANIC SERIES

METAL	APPROXIMATE VOLTAGE MEASURED TO A COPPER-COPPER SULFATE REFERENCE ELECTRODE	CONSUMPTION RATE POUNDS PER AMP PER YEAR
MAGNESIUM	-1.7	8.77
ZINC (GALVANIZING)	-1.1	6.48
CADMIUM	-0.74	-
ALUMINUM	-0.8	6.48
MILD STEEL (CLEAN & SHINY)	-0.5 TO -0.8	20.14
MILD STEEL (RUSTED)	-0.2 TO -0.5	20.14
CAST IRON (NOT GRAPHITIZED)	-0.5	-
NICKEL	-0.59	-
STAINLESS STEEL (ACTIVE) #304	-0.5	-
SOFT SOLDER	-	-
LEAD	-0.5	74.70
TIN	-0.5	42.80
MILD STEEL IN CONCRETE	-0.2	-
NICKEL	+0.1 TO -0.25	-
COPPER, BRASS, BRONZE	-0.2	25 TO 45
TITANIUM	-0.2	-
SILVER SOLDER (40% Ag)	-0.1	-
STAINLESS STEEL (PASSIVE) #304	+0.1	-
CARBON, GRAPHITE, COKE	+0.3	2.5
SILVER	+0.46	77.78
GOLD	+1.16	50 TO 140

TABLE II - GALVANIC SERIES IN SEA WATER

Corroded end (anodic)
Magnesium
Magnesium alloys
Zinc
Galvanized steel or galvanized wrought iron
Aluminum 52SH
Aluminum 4S
Aluminum 3S
Aluminum 2S
Aluminum 53S-T
Alclad
Cadmium
Aluminum A17S-T
Aluminum 17S-T
Aluminum 24S-T
Mild Steel
Wrought Iron
Cast Iron
Ni-Resist
13% chromium stainless steel type 410 (active)
50-50 lead tin solder
18-8 stainless steel type 304 (active)
18-8-3 stainless steel type 316 (active)
Lead
Tin
Muntz metal
Manganese bronze
Naval brass
Nickel (active)
Inconel (active)
Yellow brass
Admiralty brass
Red brass
Copper
Silicon bronze
Ambrac
70-30 copper-nickel
Composition G-bronze
Composition M-bronze
Nickel (passive)
Inconel (passive)
Monel
18-8 stainless steel type 304 (passive)
18-8-3 stainless steel type 316 (passive)
Protected end (cathodic)

A change in the amount of oxygen present (sometimes called "differential aeration") can also change potentials and cause local corrosion. This could happen where a pipe or cable comes out of the ground to go up a pole, occurring just at and below the ground surface. It could also happen where a direct buried cable enters and exits a duct to cross a road. Corrosion can also occur where a metal pipe or cable runs through different types of soil. This could be due to natural differences, or created by the use of different backfill material, or by running through filled areas. Different potentials created by the different electrolyte can cause corrosion currents to flow between adjacent sections of the pipe or cable.

The above are only a few sample situations where some variation of the simple battery action causes more or less self generated corrosion of metal.

There is another situation where corrosion is also caused by the flow of current from a metal into an electrolyte. However, in this case, the current is generated by an outside source.

When electric trolley cars were prevalent, many of the systems allowed DC current to return to the source through the rails and the earth in parallel. If a pipe or cable paralleled the rails, DC current would take the low resistance path provided by the pipe. At some area on the pipe near the DC system ground, current would leave the pipe or cable and continue its journey through the earth. This could cause heavy corrosion where the current left the pipe or cable.

The transit system built in Miami is said to be designed to avoid this problem. Since we do not have any trolley systems in FPL area, this type of corrosion, if it occurs, will probably come from systems of rectifiers put in by others to protect their plant. Personnel from the Corrosion Engineering Section of the FPL Power Delivery Services work with corrosion engineers of the other operating companies to prevent this condition.

To sum up the essential factors causing galvanic corrosion, we see that:

(1) We must have an electrolyte in contact with the corroding metal;

(2) There must be a DC voltage or potential difference which will cause current to flow from the metal into the electrolyte when the circuit is completed through a metallic connection. This voltage may be between dissimilar metals buried in the electrolyte, or it may be impressed from an external source.

(3) The circuit must be completed by a metallic connection.

(4) When these factors are present, direct current flows and the metal is corroded. In the cathodic protection terminology, the corroding metal is said to be the "anode", because it is discharging positive ions <u>into</u> the electrolyte. The other contact which is receiving the positive ion charge from the electrolyte is called the "cathode".

If we eliminate any one of the three essential factors listed above, we will eliminate the corrosion of the metal.

B. <u>CATHODIC PROTECTION SYSTEMS, TWO TYPES</u>

From a practical standpoint, it has been found that factor (2) above is more amenable to our control. We secure this control by reversing the direction of current flow at the metal-electrolyte interface, changing the metal from an "anode" to a "cathode". Hence the name "Cathodic Protection".

To change the direction of current flow, we must introduce a sacrificial anode with the proper potential with respect to the metal to be protected. This potential must be such that positive ions will flow from it into the electrolyte and to the metal to be protected. The potential difference must be enough to override the potential which was causing the original corrosion.

While control of direction of current flow will be our main means of protection, we can make our job much easier by also controlling factors (1) and (3) where possible. To this end, we place jackets on metallic cable sheaths and concentric neutrals and coatings on pipes. This minimizes contact with the electrolyte. We also use isolated grounding on lead sheathed cables to eliminate the metallic connection to our copper ground system. This reduces the amount of current we must reverse.

There are two methods of cathodic protection available to us; the galvanic method and the impressed current method.

1. Galvanic Protection

Galvanic protection is the simpler of the two methods available to secure cathodic protection. It is probably the best method to use when the corrosion is not too aggressive and the surface to be protected is not too extensive. To put galvanic protection into effect, choose an anode material which is higher (more negative) in the galvanic series (Table I) than the metal to be protected. As a practical matter, we use zinc anodes for most applications. The anode should be connected to the metal to be protected by an insulated wire (see DCS G-4.0.3, G-6 and G-7.0.1). This anode will be a sacrificial anode. Current will flow from it through the electrolyte to the metal to be protected. Galvanic protection is usually used where the area to be protected is rather limited, such as cable sheaths and other equipment in a manhole or vault.

2. Impressed Current Protection

a. The Rectifier

When the current obtainable from a galvanic anode source is not adequate to reverse the flow of corrosion current, impressed currents may be used. Impressed current is obtained from a rectifier, which converts ac current into dc current. FPL has used selenium rectifiers, in current ratings of 100 amperes and 20 amperes, DC. Output voltages are 24 volts and 26 volts, DC respectively. The rectifiers may be pole or wall mounted, and operate from 120/240 volt, single phase secondary. The output current is adjustable, within the range of the unit, to meet the requirements for the job.

Rectifiers are usually needed when the corrosion is very aggressive and the area to be protected is large. These units still exist in the downtown Miami area network system and must be maintained.

b. The Impressed Current Protection System

Carbon is usually chosen as the sacrificial anode for the impressed current system because of its low consumption rate. The carbon anode is buried in the earth or placed in the water at a location based on engineering judgment. The location must give the desired current flow distribution to the object to the protected.

When current flows through the electrolyte to the cathode, hydrogen gas is released at the cathode surface and adheres to it. As the current flow continues, the layer of hydrogen covers the cathode more completely, and the cell becomes polarized. The layer of hydrogen increases the resistance to current flow into or out of the cathode. Corrosion cannot occur if current flow out of the cathode into the electrolyte is stopped. The layer of hydrogen also reduces the amount of impressed current flow to the cathode. It takes a while for full polarization to develop, but as it does, the voltage between the protected cathode and the electrolyte increases. This voltage is the sum of the IR drop and the natural potential of the metal. This voltage is an indication of whether protection is being achieved. It varies from metal to metal. If measured to a copper-copper sulfate reference electrode, it should be equal to the natural potential plus an allowance for the voltage drop across the hydrogen layer. It has been suggested by one investigator that a general rule of thumb for protecting iron and steel is to shift the potential 0.15 to 0.20 volts more negative than its natural potential with respect to the reference cell or to maintain it 0.85 volts more negative than the reference cell for safe cathodic protection. As an example, suppose a steel pipe had a natural potential of -0.55 volts. Shifting it 0.2 volts would require enough current to drive the pipe potential to -0.75 volts. To be on the safe side, we would prefer to operate it at -0.85 volts but should never exceed -1.5 volts. A little extra cathodic protection current is desirable, but gross overprotection should be avoided, especially on objects with coatings. Overprotection may cause the coatings to blister. To protect galvanized steel pipe, a potential of -1.11 volts is desirable. Protected lead should have a potential of -0.65 volts. Should it be necessary to protect copper, a potential of -0.35 should be maintained.

c. Adverse Effect of Impressed Current System

An impressed current system may have a bad effect on neighboring metal structures. A thorough study must be made to be sure the system is designed in a way that it will not adversely affect neighboring facilities. Sometimes these effects may be prevented by simply bonding the two systems with an insulated conductor. Permission must be obtained from the owner before the bonding is done. The bond provides a metallic return path for any current which our system may have impressed on the neighboring system. Deeply buried anodes may help, if the neighboring facilities are near the surface of the earth.

C. POLARIZATION CURVES

Polarization curves can be used to estimate current densities required for cathodic protection. Figure 1 shows a generalized polarization curve for a hypothetical metal to be protected with a carbon anode and current impressed by a rectifier. The actual curves depend on the actual metal and the electrolyte and would have to be plotted from empirical data.

CURRENT DENSITIES FOR CATHODIC PROTECTION

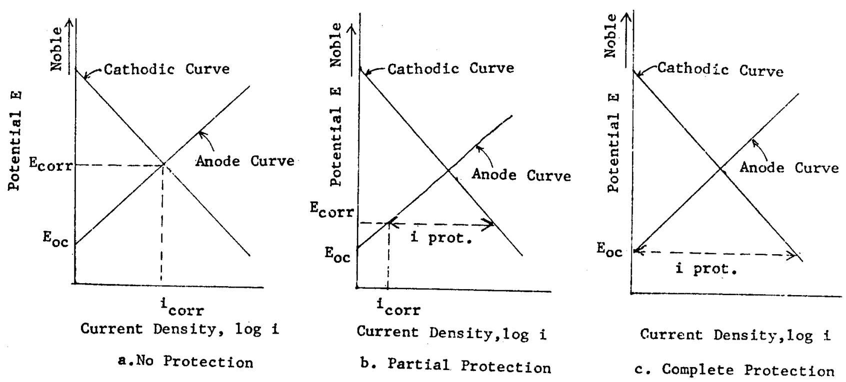


FIGURE 1

Figure 1a shows that the less noble metal is being corroded by the corrosion current, flowing from it to the more noble metal, the cathode. In Figure 1b the protecting current density has driven the potential to a more negative value than in 1a and has reduced, but not eliminated the corrosion current. In Figure 1c, the current density has been increased enough to drive the potential to its open circuit value, and the corrosion current has been eliminated. In actual practice, the current density would be increased enough to drive the potential of the protected metal slightly below its natural open circuited value.

D. THE POLARIZATION CELL (REFERENCE ONLY)

(Note: This device is no longer recommended for the protection of typical lead sheath cables as part of an isolated grounding system. The lead sheath is connected directly to the substation ground grid.)

In substations where extensive lead sheathed cable feeders originate, the cable sheath isolated ground must be kept isolated from the substation copper ground grid. However, for cable faults to the lead sheath, it would be better from a safety and relaying standpoint if the sheath had the advantage of the low ground resistance of the substation system neutral ground grid. We use a "polarization cell" connected between the cable sheath ground and the substation system neutral ground grid to accomplish this. See DCS G-22.0.1 and G-22.0.2. This cell is an open circuit for small DC cathodic protection voltages, but is a low resistance path for large ac fault currents. It is capable of carrying the full available fault current without damage.

1. Theory of Operation

The polarization cell used on the Florida Power & Light Company system consists of two sets of stainless steel plates immersed in a 15% aqueous solution of sodium hydroxide. The two sets of plates are called electrodes and the solution is called the electrolyte.

The polarization cell is similar both in physical appearance and electrical operation to the ordinary lead-acid automobile battery. In the lead-acid battery, the lead electrodes undergo a chemical change upon passage of the charging current. The polarity of the battery is established by the direction of flow of charging current. In the polarization cell the stainless steel plates are inert and do not undergo any chemical change upon passage of the charging current. Instead, decomposition of the water in the electrolyte occurs and films of oxygen and hydrogen form at the anode and cathode, respectively. The anode is the set of plates connected to the positive terminal of the charging current source, and the cathode is the set of plates connected to the negative terminal of the source. See Figure 2.

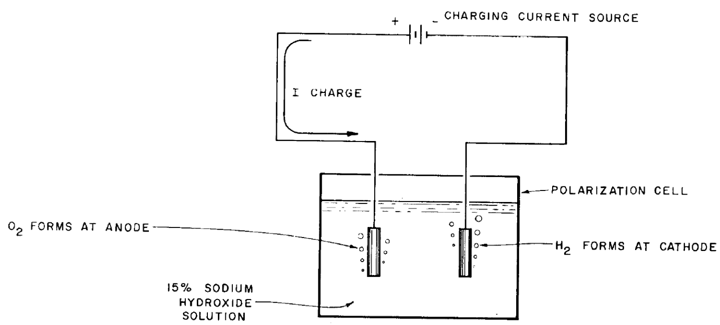


Figure 2
Polarization Cell Charging

As charging current continues to flow, gas bubbles break away from the plates. Some of the oxygen and hydrogen gas is absorbed by the electrolyte and some escapes from the cell. The cell reaches equilibrium when the rate of formation of the gases equals the rate of escape. If the charging process is allowed to continue, the water will eventually be consumed in the process. If the charging current source is disconnected after equilibrium has been reached, a potential of about 1.5 volts will exist across the terminals of the cell. In this condition the cell is "polarized" and, hence, the name polarization cell. If the terminals are shorted, the cell will act as a battery, discharge, and return to its original, neutral state. The polarization cell could be used as a battery, although a very inefficient one, since its energy storage capability is very small compared to other designs.

It is important to note that the polarization cell has no natural polarity. Polarity is established by the direction of charging current flow. Polarity may be reversed by interchanging leads from the charging source.

One other property of the polarization cell is important. The 15% sodium hydroxide solution is highly conductive and, therefore, the cell has a very low resistance. Cell resistance is determined by two factors: cell geometry (size of cell, number and size of plates, etc.) and sodium hydroxide concentration of the electrolyte. The electrolyte resistivity is a minimum at 15% concentration of sodium hydroxide. Concentrations above or below this value increase cell resistivity. Therefore, it is important to use the correct amounts of water and sodium hydroxide when making up the cell. A layer of mineral oil is used to retard evaporation of the electrolyte and maintain the 15% concentration.

2. Application of Polarization Cells

Galvanic corrosion of cable lead sheaths occurs where the lead sheath of the cable and the copper system neutral grounding form a galvanic cell with the earth acting as the electrolyte. The lead is the sacrificial metal and if this process is allowed to continue the cable sheath will be destroyed, moisture will penetrate in the paper insulation and the cable will fail. See Figure 3.

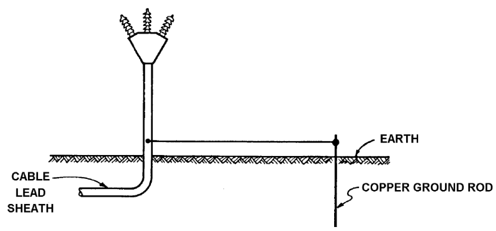


Figure 3
Unprotected Cable Sheath

There are two basic methods of protecting cable sheaths from this type of corrosion. First, the cable sheath may be isolated from earth and system neutral by means of an insulating polyethylene jacket. This will prevent the flow of current. Second, the cable sheath may be connected to a material such as zinc or magnesium which is anodic to lead and, therefore, will reverse the flow of current.

A combination of both these methods is used on the Florida Power and Light Company system. The practice shown on Figure 4 does not fulfill the requirement of a low resistance connection between the cable sheath and system neutral ground to provide a return path for fault current.

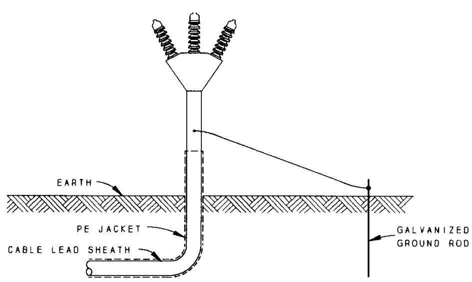


Figure 4
Protected Cable Sheath

The polarization cell, when connected to the cathodic protection system as shown in Figure 5, will provide the necessary low resistance path to ground for AC fault current. At the same time, it will sustain a small DC voltage across its terminals which will prevent shorting out the cathodic protection system.

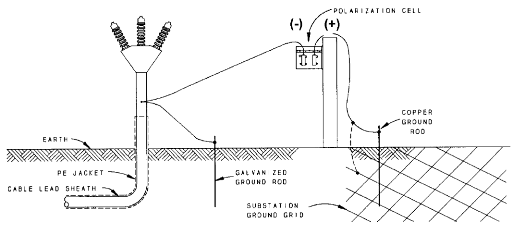


Figure 5
Polarization Cell Connection To
Cathodic Protection System

Note that the polarization cell supplies no current to the system. Rather, the cell is polarized by the lead sheath-galvanized ground rod galvanic cell until it builds up a counter voltage sufficient to block further current flow. This occurs within seconds from the time the cell is connected. Once equilibrium is reached, the cell draws very little current; only

on our lead covered cables is shown on Section G (Grounding) of the DCS. Section G also shows details of installation of the anodes. See also the Grounding Section 2.4.3 B "Cable in Duct and Manhole Systems" of this Manual.

E. ANODIC PROTECTION

Some metals show active-passive behavior. Iron, stainless steel, titanium, aluminum and chromium all have active and passive states. It is possible to protect these metals by anodic protection. Current is applied in a direction to drive the potential more positive. At first, a rather large current will be required to get the metal through its active phase. When a critical value is reached, the metal will be driven into a passive state and the current will decrease dramatically. Corrosion will not be eliminated, but will be greatly reduced. If the metal is driven to too positive a potential, it will leave the passive stage and corrosion current will increase greatly. Anodic protection is useful to protect tanks holding acids, but is not normally used in the protection of electric underground distribution systems.

The Corrosion Engineering Section of the FPL Power Delivery Services has the instruments and expertise for making cathodic protection studies and measurements. When difficulties arise which are not covered by Distribution Construction Standards and other references, they provide engineering assistance.

F. AN UNSOLVED CORROSION PROBLEM

Since 1962, utilities have installed millions of feet of direct buried primary cable in underground residential distribution systems (URD). Large quantities of this cable has a bare, concentric neutral. This design resulted in an economical cable which seemed ideally suited for the job it had to do.

The bare copper neutral was expected to be cathodic because of its position in the galvanic series, and thus not subjected to corrosion. However, cable failure investigation reports have revealed neutral wires completely severed due to corrosion.

Since 1978, FPL is using jacketed cable to retard the penetration or moisture in the insulation and to minimize the neutral corrosion.

G. PREVENTIVE MEASURES

From what we have learned about corrosion, certain considerations included in the design of distribution systems will minimize corrosion and the amount of money spent on prevention.

Some of these considerations are:

146. Try not to use metals with widely differing potentials close together in the soil or water.

147. If you must use metals, with widely differing potentials, buried close together, do not permit a metallic connection between them.

148. Coatings or coverings on the metal will prevent corrosion. However, a break or scratch in the coating may concentrate corrosion at that point and result in severe damage if protection is not provided.

149. Do not overprotect with cathodic protection. The hydrogen generated may ruin the coating. In some cases, it may damage the metal. Some stainless steels may experience stress cracking due to the presence of hydrogen.

150. Avoid deep crevices in objects to be cathodically protected. It is difficult for protective currents to reach the bottom of these crevices.

151. Where indicated, specify galvanic protection with sacrificial anodes of zinc or magnesium. Set up a plan to check and replace anodes when used up.

152. Where more protection is needed than can be provided by galvanic protection, specify impressed current protection. Make a thorough study of the area to be sure your installation will not damage adjacent systems. Coordinate with the owners of neighboring metal structures (water, gas, telephone, etc).

2.7.2 CORROSION CONTROL - PAINTS & COATINGS

A. GENERAL

Paints and coatings used for corrosion protection should exclude all electrolytes from contact with the metal to be protected. If they do a good job of this, corrosion will not take place. A bonus received may be in improved appearance of the protected equipment. To achieve this result, the paint or coating must be chosen to blend, rather than clash, with the environment.

B. METALLIC COATINGS

1. Galvanized (Zinc) Coatings

a. Overhead Line Hardware

Overhead line hardware must be strong and economical. For this reason, most of it is manufactured from hot rolled steel, malleable iron castings or other ferrous materials. In Florida's semi-tropical environment, the hardware would soon rust out if not protected. Rust is a form of corrosion, which occurs when moisture and oxygen are present on an unprotected surface of ferrous material. Note again that moisture must be present for corrosion to take place.

Line hardware is subject to hard usage. A paint coating would soon be abraded and scratched. Corrosion would then be localized at the exposed ferrous surface and the life would be short.

Instead of painting, a coat of zinc is put on the hardware by a process called "hot dip galvanizing". This leaves a good thick coat of zinc over the ferrous material. In addition, the heat of the molten zinc causes a layer of zinc-iron alloy to be formed on the ferrous material. The zinc forms a film on its surface, which inhibits corrosion of the zinc. In addition, if the zinc is scratched away from the iron, the zinc will protect the iron, since it is more negative in the galvanic series than iron. In the presence of moisture at the scratch, current will flow from the zinc to the iron, offering cathodic protection to the iron. This gives a long life to all hardware in normal atmospheres. It is especially important to buried anchor rods. Zinc in the earth with copper will be corroded but the steel rod will be protected. Longer life will result for galvanized anchor rods and pipes if they can be isolated from copper ground systems.

In beach areas, the life of galvanized hardware has been shortened. Over a period of years, the zinc may disappear, leaving the steel to rust. This seems to happen fastest at pole locations where the washing action of rain is restricted and where the zinc is subjected to erosion by blown sand. One of the worst locations is at the pin of suspension insulators, where the washing action is nil.

It has been mentioned that zinc galvanizing builds up a surface film in normal atmospheres. This film is an insulator. It can cause arcs, radio, and TV interference in the galvanized clevis-and pin linkages of dead-end insulators. The arcs occur when the film breaks down and allows the capacitive and leakage currents of the dead-end to flow. Full tension on the dead-end usually eliminates this problem.

b. Galvanized Guy Wire

FPL uses galvanized steel wire for distribution guying. Guy wire may be purchased with "A", "B", or "C" hot dipped galvanized or electro-galvanized coatings, "C" coating being the thickest zinc covering. FPL uses the "C" coating to get the most protection.

c. Galvanized Ground Rods

Galvanized ground rods are used on isolated grounds for cable systems where copper would be undesirable. The comments in B.1.a above concerning galvanized hardware also apply to ground rods. Ground rods, like anchor rods, are more subject to attack since they are in the soil electrolyte. Contact with more noble metals must be avoided.

2. Aluminum-Clad Guy Wire

Aluminum-clad guy wire is also available and serves about the same purpose as galvanized guy wire. It is presently not used in distribution line construction, but is listed in the transmission section of the Standard Material Catalog.

3. Copper Coatings

a. Anchor Rods (For reference only)

In filled areas known to be very corrosive to galvanized anchor rods, and in other very corrosive areas, copper-clad anchor rods with bronze eyes are available. A closed bronze nut is provided for the lower end of the rod to seal off the steel core and prevent corrosion.

Care should be taken not to damage the copper coating, as corrosion of the load bearing steel member will result.

b. Guy Wire (For reference only)

Copperweld wire has a steel core and an outer layer of copper. It is produced by starting with a rod, which is steel inside, and copper on the outside. This is drawn down in diameter and is finally drawn into the desired wire size. The wire is available with two thicknesses of copper. FPL buys guy wire with the thinner coating, called 30% conductivity. Wire with 40% conductivity is also manufactured. Copperweld guy wire is used in severe salt spray areas where galvanized grade "C" coating has not performed well. Since the galvanized eye of the anchor rod is above ground, no special precautions are necessary where the copperweld guy wire attaches to the eye. Copper stands up well in salt spray corrosion areas. Copperweld guy wire has given good service. It must be realized, however, that if the copper layer is removed accidentally at a point, a pit of ferrous corrosion may form at this point. Copper is more noble than steel and will attack the steel if an electrolyte is present at the scratch. The steel wire may be weakened to the point of failure without the corrosion being noticeable. For this reason, it is important to use care in the handling and installation of copperweld guy wire, so as not to damage the coating.

c. Copper-Clad Ground Rods

FPL uses both galvanized and copper-clad ground rods. What has been said about damage to copperweld guy wire also applies to copper-clad ground rods. One difference is that the rods are driven into the earth and are therefore in an electrolyte. They are even more subject to damage if the copper is removed from the steel rod. Copper-clad ground rods are used where the grounds are part of the system neutral grounding. These ground rods have been very satisfactory, overall. In some mangrove swamp areas, or filled areas where a lot of hydrogen sulfide gas is present, some corrosion of the copper has been noted.

4. Metal Spraying

Metal spraying equipment has been developed to the point where a coating of molten metal may be applied to a metal structure in the field. This is not ordinarily used in distribution but is used in power plants. Should a need for this technique develop in the distribution field, it is available.

5. Electroplating

Pole line hardware and other items have been offered where the zinc coating has been deposited by electroplating instead of by the hot dip galvanizing process. In general, FPL has preferred the hot dip galvanizing as giving us a thicker, less porous coating alloyed to the protected metal.

6. Inorganic Zinc Coating

The East coastal area of Florida, extending north from Jupiter Inlet up through St. Augustine Beach is designated as a Severe Salt Spray Area (See DERM 2.8.1). In this area, the standard galvanized hardware will corrode in 5-10 years. In an effort to extend the life of these items, FPL has started using a High-Ratio Inorganic Zinc (IOZ) coating that is applied to the galvanized hardware for use in the Severe Salt Spray Area.

The IOZ coating acts as an inert barrier protecting the galvanizing and steel beneath. The IOZ coating has the unique property of being able to "self-heal" minor scratches. Larger scratches cause the underlying zinc galvanizing to become active and provide cathodic protection to any exposed steel. This combination of corrosion protection, barrier protection and cathodic protection extends the life of normal galvanized hardware by two to three times in the severe salt spray area. Hardware coated with inorganic zinc is limited for use only in severe salt spray areas because of the increased cost.

The application of the IOZ coating requires a qualified coating technician with access to specialized equipment. The galvanized hardware must first be cleaned of oil, grease, flux or other contaminants by a suitable solvent or cleaning agent. Once cleaned, the hardware is "sweep" blast cleaned using a fine aluminum oxide medium to remove zinc oxides and to lightly roughen the galvanized surface without totally removing the zinc galvanizing. After the blast cleaning, the surface is blown down with clean compressed air to remove loose or embedded abrasive. The hardware must be coated within a few hours of the blast cleaning to maximize adhesion and to prevent oxidation of the zinc with the atmosphere. The coating application must be closely controlled to prevent application-related failures.
Additional corrosion protection to field installed hardware can be provided by the application of inhibited "Gray Wax^{TM}" to components that show signs of coating abrasion after installation, particularly bolt threads and nuts.

C. NON-METALLIC COATINGS

1. Porcelain Coatings (For reference only)

Some FPL transformer tanks have "porcelainized" finishes. This is a thin layer of colored porcelain, which has been fired to the tank to exclude moisture.

This type of transformer tank is very successful in a salt spray area. If handled roughly, it will chip. Even then, there is an alloy surface left which has fair resistance to corrosion. Care must be taken not to chip the coating at hanger lugs, etc. FPL standards provided lead washers to be used to avoid chipping at points where hanger bolts clamped down on hanger lugs. The size limitation of the manufacturer's process was the tank for an aerial 75-kVA transformer. This type of transformer is no longer purchased.

2. Inhibitors

There are many applications in distribution where noble metals must be joined with a less noble metal. Quite often, there are gaps and crevices where moisture may gather and cause galvanic corrosion of the baser metal. This is especially true in seacoast areas. In most cases where different metals are joined in a connection, aluminum and copper are involved. If the members joined are non-current-carrying, resistance in the joint may not be objectionable, and may even be desirable from a corrosion standpoint. An example might be the linkage from an aluminum strain insulator cap clevis to a galvanized iron clevis pin.

The situation is different in a current-carrying connection. Even a small resistance can cause extreme heating when large currents are involved. Heating usually further degrades the connection and a "runaway" condition may result.

The ideal connection is one in which the resistance is maintained at a value less than an equivalent length of the larger wire entering the connection.

In the presence of oxygen, an insulating film forms quickly on aluminum. An oxide also forms on copper, but it does not form nearly as quickly and is a better conductor than in the case of aluminum.

For aluminum-to-aluminum or an aluminum-to-copper connection, the aluminum must be abraded to remove the surface film and an inhibitor applied to keep oxygen away from the cleaned aluminum surface. Some inhibitors have chemicals, which reduce aluminum oxide; others are simply stable greases to exclude moisture. The ones FPL uses are of the latter type. The compound must be inside the connector and fill the space not occupied by the conductor to properly exclude moisture (the electrolyte). Do not be afraid to get the compound between the two conductors in the joint; it will squeeze out of the way and leave good, sealed metallic contact when pressure is applied to the connector by the compressing tool or the bolts.

Actually, if looked at with great magnification, a connection of two metals is not a continuous contacting surface. Instead, there are many discrete points of contact and many areas where there is no contact. In some of the no-contact areas, the distance between contacting surfaces is only the diameter of one molecule of the inhibitor. There is an electrical phenomenon called "thin film conduction" which allows current to flow through the grease in these areas, even though there is no metallic contact. Thus the inhibitor, in addition to preventing deterioration of the connection, actually improves its initial conductivity.

The rules for preventing corrosion in a copper-to-aluminum connector are the same as discussed previously for cathodic protection; namely:

23. Where possible, do not join these widely dissimilar metals. Where it cannot be avoided, make the connector body of the less noble metal (aluminum) so that the larger mass and surface of the connection will be aluminum. Any corrosion and loss of metal will be of the aluminum and its significance will be minimized by spreading it over a larger area and mass.
24. Keep moisture (the electrolyte) out of the connection. Clean the conductors and cover with inhibiting grease. Fill the connector with grease and complete the connection. On overhead lines, put the copper at the bottom of the connector, so that gravity will not cause copper corrosion salts dissolved by rain to run down and contaminate the aluminum. Remember it alphabetically: “A over C” – aluminum over copper.
25. We cannot avoid the metallic connection between aluminum and copper, since this is the purpose of the connection. Therefore, we must rely on excluding contact with the electrolyte to prevent the development of a corrosion cell. Only use connectors approved for joining aluminum to copper.

Many of our connectors come with inhibitor packed in the grooves or barrels. After cleaning, the aluminum conductor should be immediately put into the connector-contained inhibitor.

From a corrosion prevention standpoint, the tubular compression connector with an internal barrier is probably the most efficient. For copper-to-aluminum connections, the body would be of aluminum. With inhibitor in the tube, the only corrosion cell possibility would be where the copper enters the tube. Corrosion would be spread over the larger diameter tube and would not affect the copper or aluminum conductor. This type of connector is also easier to seal with tape or rubber mastic.

Other satisfactory copper-to-aluminum connectors have aluminum bodies. They keep the conductors separated in parallel configuration with enough separation so the copper cannot attack the aluminum conductor. It must spread its corroding current over the larger body of the connector. The connector may be a bolted or a compression type, but must be filled with inhibitor.

Conductive greases can be used on the sliding contact areas of disconnect switches and fuse switches. The intent is to make them operate more smoothly and improve contact conductivity. Contact paste inhibitor (M&S #522-25500-2) must <u>not</u> be used on moving contact surfaces, since it tends to harden after thermal cycling.

3. <u>Jacketing for Corrosion Prevention</u>

Jackets can be used on cable and some other equipment to exclude moisture, thereby preventing corrosion.

FPL uses polyethylene as a jacketing material over the lead sheath of PILC cable, and over the copper concentric neutral of URD cable. A polyethylene jacket is also used over the corrugated copper sheath of our submarine cable (CLX).

As mentioned before, jackets will do a good job of preventing corrosion as long as they are intact. A break in the jacket may concentrate corrosion currents at that point and accelerate corrosion. For this reason, cathodic protection may still be a wise precaution.

The value of the jacket or coating is that it reduces the area exposed to corrosion. Much smaller protection currents can be used, with resultant savings in capital and operating costs.

4. <u>Painting for Corrosion Protection</u>

Paints may also be used to exclude moisture and thus corrosion from the surface of a metal. To be effective, paints must be put on without breaks or thin spots and must not be porous. Preparation of the surface is very important to an effective paint job.

In distribution, the main objects needing paint are the tanks of transformers, reclosers and switches.

Equipment mounted in underground vaults and pad mounted equipment usually have more severe corrosive conditions than pole mounted equipment.

To obtain a good, long-lasting paint job, the surface to be painted must be properly prepared. Grease, scale, rust, and weld splatter must be removed. A metal primer or surface treatment must be applied. A finish coat of acrylic enamel, oil base baked enamel, or epoxy enamel may be applied. Care must be taken to secure sufficient thickness of paint on all sharp edges.

Some manufacturers coat their tanks with powdered vinyl paint, using electrostatic attraction to get the coating on evenly. The tank is heated before the vinyl powder is applied in order to melt and hold the powder.

Subway transformers usually have an epoxy-tar primer and finish coat. Often this is black, since the transformer is out of sight of the public.

The bottoms and the lower areas of vault type and pad mounted transformers may also be coated with a coal tar epoxy paint to make them more resistant to abrasion and corrosion from surface water. Some manufacturers also offer a thicker layer of powder coating in these areas.

Zinc-rich paints afford good protection from corrosion, especially in touching up breaks in coatings on galvanized steel. Zinc paints may have either an organic or an inorganic base. The organic base zinc paint is easier to apply, since less surface preparation is needed. The inorganic base zinc paint requires very thorough surface preparation, but is more heat resistant, more resistant to organic solvents and is not flammable. Zinc-rich paints will protect even if porous in the same way zinc galvanizing protects the base metal.

Field painting of equipment is always easier and more effective if it can be done before complete failure of the original paint job. For this reason, pad mount transformers should be painted as soon as practical after construction has been completed at a job site.

It is sometimes necessary to paint or repaint an iron or steel surface, which has rusted. A wire brush may remove all loose rust and scale but leave some tightly adhering rust. The surface may be treated with a commercially available phosphoric acid solution. This will produce a chemical reaction and result in an iron phosphate deposit on the surface in place of the rust. This phosphate coating is a good base for a primer or zinc chromate paint.

5. <u>Anodizing for Corrosion Protection</u>

Anodizing is often used to coat aluminum with a hard oxide coating, which will give the surface some protection from scratching and serve as an excellent base for paints. The oxidizing is done by immersing the aluminum in sulfuric acid and making it the anode in a direct current low voltage circuit. The layer of oxide is porous. To improve the corrosion resistance of anodized materials, they are usually sealed in boiling water or a boiling sodium dichromate solution. Sometimes, for ornamental panels or objects, a dye may be applied to the oxide coating. For other uses, the oxide coating may be painted over.

6. <u>Other Paints and Coatings</u>

There are many other types of paints and coatings, some of them excellent for specific purposes. When problems come up which are not covered by this section or by your experience, the Corrosion Engineering Section at the Power Systems Test Lab may be of assistance.

D. <u>OTHER REFERENCES</u>

16. "Instrumentation" by M.C. Miller, "Proceeding of The First Annual Underground Corrosion Short Course. Appalachian Underground Corrosion Short Course, Engineering Experiment Station, West Virginia University.

17. Reference Book on "Instruments for Corrosion and Cathodic Protection Testing" - American Gas Association, 120 Lexington Avenue, New York, N.Y.

18. Chapter 14, Underground Systems Reference Book, Edison Electric Institute, 90 Park Avenue, New York, N.Y. 10016

19. "Control of Pipe Line Corrosion" - A.W. Peabody, NACE, Katy, Texas
20. NACE (National Association of Corrosion Engineers) Basic Corrosion Course - NACE, Katy, Texas
21. "Corrosion" - 2 volumes L.L. Sheir - John Wiley Publishing Co.
22. Corrosion Causes & Prevention Speller - 3rd Edition - McGraw Hill.
23. Proceeding - Appalachian Short Course on Underground Corrosion - Experiment Station West Virginia University.

Section 2.8.1 has not been updated since December 2000. Please refer to the on-line version for updates prior to using. InFPL/Power Systems/Reliability/DEO/Publications/DERM

2.8.1 SALT SPRAY AND OTHER CONTAMINATIONS - SALT SPRAY PROBLEMS AND DESIGNS

A. SALT-SPRAY AND OTHER CONTAMINATION

One of the unique characteristics of the Florida operating environment for an electric utility is the exposure to various forms of contamination. The most obvious contaminant is the salt-spray or salt-fog of the coastal regions.

B. CONSTRUCTION AREAS

One of the problems in dealing with construction in "salt-spray", “severe salt-spray” or "contaminated" areas is in defining exactly what we mean by these terms. For the purposes of this discussion, the following conventions will be followed as the accepted corporate definitions of "salt-spray areas", “severe salt-spray” and contaminated areas for distribution construction.

The specific boundaries of the salt spray, severe salt spray, and contaminated areas can be seen on the GIS Maps. To view these maps go into IN FPL, Business Units, Power Systems, Geographic Info Systems, Interactive Maps, Feeder Line Sections and click on Salt Spray option.

1. Salt-Spray Areas

   c. All barrier islands and areas on the outside (Atlantic or Gulf side, as appropriate) of the Intracoastal Waterway on the east and west coasts of all FPL areas.

   d. First 500 feet from the average high tide mark for unprotected coastal areas (i.e. - where barrier islands are not present).

   e. Any additional areas locally designated as salt-spray areas, based on past experience and/or engineering judgement.

2. Severe Salt-Spray Areas

   f. Area along the East Coast of Florida extending North from Jupiter Inlet.

   g. All barrier islands and areas on the outside of the Intracoastal Waterway on the east coast of Florida north of Jupiter Inlet.

   h. First 500 feet from the average high tide mark for unprotected coastal areas (i.e. – where barrier islands are not present.) north of Jupiter Inlet.

3. Contaminated Areas

   i. All areas within 1000 feet of the average high tide mark which are not within the boundaries of the salt-spray areas, as defined above.

   j. Areas subjected to corrosive and/or contaminating atmospheric effects, due to industrial or chemical pollutants. Examples might include chemical factories, paper plants, cement factories, rock pits, etc.

   k. Areas which are subjected to aerial spraying of contaminants (i.e., pesticides & fertilizers).

   l. Other areas locally designated as contaminated areas, based on past experience and/or engineering judgement.

4. Standard Construction Areas

   m. All areas which are not considered to be salt-spray, severe salt-spray or contaminated areas.

C. DESIGN POLICIES FOR NEW CONSTRUCTION

Note: In each of the four construction categories listed below, the alternatives are ranked from the most preferred to the least preferred method.

1. Salt-Spray Areas

n. 13 kV overhead vertical construction with 13 kV salt-spray equipment (35 kV class post insulators) and aluminum conductors. The vertical configuration provides better washing action from rain than other configurations, due to the use of horizontal post insulators. the insulators should be pointed toward the source of contamination, when possible, in order to minimize the build-up of contamination which can accumulate under insulator skirts.

o. All hardware is to be bonded to the system neutral and lightning arrester spacing is to be the same as on concrete poles.

Note: Three phase construction in inaccessible areas must be framed on cross-arms. Every effort should be made to ensure that all three phase overhead construction is in accessible locations.

p. 13 kV or 23 kV URD (cable in conduit) construction with salt-spray equipment (stainless steel pad mounted switches, stainless steel bottoms for pad mount transformers, etc.). The URD feeder and lateral runs should be looped or have alternate feeds in order to provide for maintenance or replacement of pad mounted switchgear and transformers.

q. Duct and manhole system, (only where required).

r. 23 kV overhead construction is not a recommended option for new construction.

Existing 23 kV salt-spray installations may be maintained with special salt-spray treatments (i.e., silicon rubber coatings), copper conductors, and a preventative maintenance program (scheduled cleaning and pro-active material changeouts) as required by local environmental conditions. Washing the insulators may be considered if conditions warrant. Use 45kV class post insulators.

2. Severe Salt-Spray Areas

s. All items listed for salt-spray areas applies for the severe-salt spray areas plus the items listed below.

t. Use inorganic zinc coated hardware.

u. No installation of new OH 23 kV construction.

v. In existing 23 kV OH problem areas use 45 kV Polymer tie top post insulators with all aluminum tie wires on aluminum conductors if re-insulating.

3. Contaminated Areas

w. 13 kV or 23 kV overhead vertical construction with salt-spray equipment and aluminum conductors.

x. 13 kV or 23 kV URD (cable in conduit) construction with salt-spray equipment (i.e., stainless steel pad mount switches, transformers, etc.).

y. Duct and manhole system, (only where required).

4. Standard Construction Areas

z. 13 kV or 23 kV overhead modified vertical or crossarm construction with standard non salt-spray equipment and aluminum conductors.

aa. 13 kV or 23 kV URD.

bb. Duct and manhole system.

D. FRAMING METHODS FOR OVERHEAD CONSTRUCTION IN SALT-SPRAY OR CONTAMINATED AREAS

Vertical construction should be used in salt-spray or contaminated areas. Insulator brackets and through bolts must be bonded to the neutral on wood poles to prevent leakage current from burning the wood. Switch bases and other metal brackets must also be grounded. Insulators must have adequate leakage distance over the surface of the insulator to prevent flashover conditions from developing.

Distribution Construction Standard E-4.0.1, "Insulator Application" specifies the type of insulator needed for salt-spray, severe salt-spray, and contaminated areas. Two sizes of Polymer suspension (deadend) insulators are currently used. The shorter one is used for 13 kV, 13 kV SS, and 23 kV. The longer one must be used in 23 kV salt spray areas. On older style porcelain installations, three suspension insulators (also known as "J.D.'s" or "discs") are used for 13 kV deadends and four are used for 23 kV deadends.

Since the bases of the insulators are grounded, the BIL of the lines in salt-spray or contaminated areas is limited to the BIL of the insulators. Therefore, phase to neutral spacing on the poles may be reduced, provided that adequate midspan phase to neutral clearances are maintained.

Arresters are required for line protection at the same intervals specified for concrete poles in Table I, Section 2.9.1, of this manual.

E. MATERIAL FOR OVERHEAD CONSTRUCTION IN SALT-SPRAY OR CONTAMINATED AREAS

1. General Material Considerations

The principle behind most corrosion phenomena encountered with metals in salt-spray or contaminated areas is a galvanic reaction which occurs when two dissimilar metals are placed in contact with each other in the presence of an electrolyte. Typically this might be galvanized mild steel in contact with bronze or copper, in the presence of salt water, the electrolyte. For a more exhaustive treatment of corrosion and cathodic protection, please refer to DERM section 2.7.1.

As a practical matter, we can take several approaches towards coping with corrosion.

Paints and coatings (plastic, vinyl, copperweld, etc.) have proven to be somewhat effective in coping with this problem when properly applied. Unfortunately, when the protective layer has been breached - cracked, scratched, abraded, or whatever - the deterioration of the substrate metal often continues for extended periods of time under the surface. This is especially troublesome since it is difficult to detect camouflaged deterioration before it causes extensive damage to the metal, often necessitating replacement of the affected component. The use of a zinc-rich primer or paint is often a good compromise when corrosion problems are not severe. Galvanizing, especially hot dip galvanizing where the zinc actually forms a bonded layer with the steel is better yet. In this case, not only are the zinc coating and the transition layers providing a coating, they also tend to be "self-healing" in the cases of breaks in the surface by steel will begin to appear rusted before the strength of the material has suffered extensively. Unfortunately, the galvanized surface is susceptible to abrasion, particularly by wind blown particles (sand) in the coastal areas. The topics of paints and coatings are dealt with in a more thorough manner in DERM 2.7.2.

In the severe salt spray areas identified above, FPL now uses an Inorganic Zinc Coating applied over the standard galvanized hardware. In these areas standard galvanized hardware lasts only 5-10 years. With the added coating, these items are expected to last approximately 15 to20 years! Since this coating is very expensive, it is only used in the designated “Severe Salt-Spray” Areas.

The most successful ways of dealing with the effects of corrosion is to use a material which is inherently resistant to corrosion without the need for protective coatings. Some of the more successful metals traditionally used in salt-spray or contaminated areas are copper, bronze alloys, and stainless steel (especially 304L). Unfortunately, these materials tend to be much more expensive, and sometimes (as in the case of stainless steel) harder for the manufacturer to form than painted or galvanized mild steel.

There has recently been interest in using aluminum alloys in salt-spray areas. Certain alloys appear to be well suited for this environment, while others are not. FPL has already achieved some successes in these applications, particularly with the aluminum secondary forks and pins. We are evaluating additional opportunities in this area and expect to have more developments in this area in the coming years.

Plastics, ceramics, polymeric, and composite materials offer resistance to corrosion, but they may not be suitable for certain applications due to strength, rigidity, temperature, or impact limitations. These materials are often susceptible to damage from ultraviolet (UV) radiation or even the electrical fields associated with electrical equipment. We expect additional technological developments in these materials over the next several years.

2. Insulators

In salt-spray or contaminated areas, leakage distance (also known as "creepage distance" or simply "creep") from the conductor to ground over the surface of the insulator becomes important. This is applicable not only to line insulators, but also to bushings, lightning arresters, disconnect switches, and cutouts. Experience has shown that a leakage distance of about two (2) inches per kV of phase to ground voltage is required for the successful operation of 13 kV and 23 kV overhead lines in salt-spray areas. The exact leakage distance varies somewhat with the shape and position of the insulator, as well as availability.

Some of FPL's insulators used in salt-spray areas have been purchased with a "resistive glaze". The insulator becomes a high ohmage resister connected from the conductor to ground. This tends to stabilize the potential gradient over the surface of the insulator and eliminate sparking, along with the resultant radio and TV interference. In addition, the I^2R energy dissipated in the insulator tends to keep the surface dry in humid conditions when damp, contaminated insulators might otherwise lead to line flashovers and interruptions.

The resistive glaze insulators have largely been replaced by RTV (Room Temperature Vulcanizing) silicon rubber coatings. These materials, marketed as "Sylgard" or "Wacker" work by causing moisture to "bead up" rather than forming conductive sheets of contaminated solution. Based on FPL's experience and manufacturer's testing, we expect these coatings to remain effective for five to fifteen years, perhaps even longer. These coatings may be applied to insulators, bushings, and other types of porcelain insulators.

Certain polymeric insulators have shown great promise in both being resistant to contamination and tracking, as well as providing the extended creepage distances which we require for these applications. We have not yet determined how well these materials will stand up to the long term effects of exposure to our high UV and contamination levels.

New 23 kV OH Construction should not be used in Severe Salt Spray Areas. However, in those existing areas, a new 45 kV polymer insulator should be used instead of the 45 kV porcelain insulator when doing short extensions or re-insulating the line. The polymer insulator is a silicon compound that provides excellent hydrophobic and recovery characteristics, which control leakage current and arching in highly, polluted or seacoast environments. These insulators have an aluminum tie top head and special all aluminum preformed ties should be used.

3. Surge Arresters

Polymer MOV arresters are to be used in contaminated areas. Salt-spray adapters with an external gap and insulator used to be added to polymer MOV arresters to increase the leakage distance in salt-spray areas. This is no longer needed.

4. Conductors

Extending or reconductoring in salt-spray or contaminated areas shall be constructed with #4AAAC, #1/0AAAC, #3/0AAAC or #568ACAR aluminum conductors. Existing construction in salt-spray or contaminated areas which already has copper conductor shall be maintained with copper. Extensions to copper circuit shall also be made with copper conductor. In copper construction, soft drawn copper shall continue to be used for jumpers on lines and associated equipment.

5. Transformers

Aerial transformers with stainless steel tanks and long creepage porcelain bushings are to be used in salt-spray areas.

6. Cutout and Disconnect Switches

Cutout switches with long creepage porcelain bushings and all copper alloy or stainless steel construction are to be used for all salt-spray and contaminated area construction. Bronze and copper "Powerdyne" type switches are to be used for in-line switch applications in salt-spray and contaminated areas. FPL has all stainless steel and copper alloy pole mounted (sometimes called "underhung") 25 kV switch for all salt-spray applications. Please remember that disconnect switches are to be installed in locations accessible to vehicles.

7. Pad mounted Switchgear

Pad mounted switchgear with stainless steel cabinets should be used in all salt-spray applications and are recommended for use in contaminated areas as well.

8. Pad mounted Transformers

Single phase padmounted composite hood transformers are to be used in all salt spray applications. The new unit provides a patented polyester cover jointly developed by ABB and FPL to eliminate corrosion on transformer hoods and sills (areas with the worst corrosion).

Pad mounted transformers with stainless steel parts in critical areas (sill, hood, and tank bottom) should be used in all salt-spray applications and are recommended for use in contaminated areas as well. The use of new transformers having stainless steel parts and superior paint is strongly recommended for salt-spray and contaminated areas.

2.9.1 ELECTRICAL PHENOMENA - SURGE PROTECTION - LIGHTNING

INTRODUCTION

Florida has more thunderstorm days annually than any other part of the United States. Since thunderstorms are so frequent here, there has always been a tendency for Florida residents, even FPL engineers, to feel that we are largely at the mercy of the elements. The feeling has been that power outages and damage to the electric power system from lightning is a price one has to pay for living in Florida, and that these things just will happen, regardless of how much effort is put into lightning protection. These fatalistic ideas are only partly true. Over the years, FPL has waged an endless battle against outages and damage due to lightning surges. Little by little we have learned many effective measures that can be taken. We continue to procure improved materials and devices which perform more reliably than their predecessors.

In recent years, with the increasingly widespread use of computers, digital clocks, VCR's, microwave ovens and other electronic devices in homes and offices, the public has become more aware of service interruptions, and less tolerant of even brief outages of a few seconds' duration. With the company's increased emphasis upon quality, a major aspect of which is service reliability, this problem has received a great deal of attention. After all, lightning is blamed for more service interruptions on the FPL system than any other cause.

Experience has shown that surge arrester installations and overhead groundwire installations have been rendered largely ineffective because of inadequate grounding, pole bonding, and lack of maintaining short lead lengths. Lightning surges are quite unforgiving of poor workmanship in the design and construction of lightning protection schemes.

If service interruptions due to lightning surges are to be drastically reduced - and they must be -it is extremely important that all personnel doing field engineering work be thoroughly familiar with the theoretical and practical information contained in this section, as well as that in Section 2.4 - Grounding, Section 3.6.1 - Equipment: Surge Arresters, and DCS G-2. It is important so that you will be able to design and specify proper installations which will perform as intended. It is also important so that you will be able to recognize incorrect or substandard installations in the field, and take action to get them corrected.

Several improvements in FPL's overall surge protection policy have resulted from recent studies. Additional improvements are expected in future as further studies, analyses, and tests are completed. Among recent changes are the following:

24. Lightning arresters for aerial transformers are now tank mounted.
25. Overhead groundwire construction has been introduced as an alternate construction standard for FPL service areas where direct strokes to distribution lines are prominent.
26. Pole grounds are only driven at arrester stations or equipment locations.

A. LIGHTNING IN FLORIDA

Lightning annually contributes to more than a quarter of the outages on FPL's system. This is more than twice the next highest cause. It seems that FPL's service area is a natural lightning generator from May to October. The peninsula of Florida heats up during the daylight, causing the humid air to rise. The air over the ocean moves in to replace the heated air. Cooler air, higher above the ocean, drops to take the place of the air which has moved inland. All this air movement causes the humid air, which has formed into clouds, to "boil-up" into enormous thunderheads. The anvil shaped top will reach an elevation exceeding 50,000 feet. With this circulation of air, the thunderheads move from over the interior of the state to the coastal areas in the late afternoon. Lightning will tend to dissipate as the storm approaches the coast. Since the land mass will cool more rapidly than water during the night, the air circulates in the opposite direction. Some thunderstorms will come in from the ocean in the early mornings, but these are not as frequent as afternoon storms. Cold fronts during the spring and late fall add to the summer storms. The fronts flow south over the warm humid air hugging the earth. The warm air rises and cold air falls creating a circulation which produces thunderstorms. The thunderheads will form generally along an east-west line behind the front. These fronts spawn occasional tornadoes which play havoc with the Company's installations.

B. ISOKERAUNIC LEVEL

The Weather Bureau reports thunderstorms by the number of days thunder is heard. The average number of days thunderstorms are heard during one year is called the isokeraunic level. (See Figure I, the isokeraunic map of Florida.) It has been the practice to use this figure to estimate the number of lightning flashes to the ground. It has been found that there is very little direct correlation. Thunderstorms in the Temperate Zone have only one thunderhead. Tropical storms normally have several and will last three times as long as the single thunderstorm in the Temperate Zone. Considering a high estimate, Florida would have approximately 3 flashes to one square mile for each thunderstorm day, or 180 to 300 per year. The chances of FPL's lines being struck by lightning are the highest in the country.

C. THE ANATOMY OF LIGHTNING

There are many theories on how the separated positive charges are formed. We'll leave that to the physicists to argue. We do know the updraft carries the positive charges to the top of the thunderhead. The negative charges remain at the bottom. As the charges build up in the cloud, the earth will also build up charges of opposite polarity to the bottom of the cloud. This is when the top of a sailboat mast will visibly glow. This is known as St. Elmo's Fire. If there is lightning, and you feel your hair rise --- immediately fall flat on the ground. You are building up a charge and may be subject to being hit by lightning. At this time the "stepped leader", or first stage of lightning begins. It is a bright streak about 150 feet long and three to thirty feet wide extending from the bottom of the cloud. It descends toward the ground in jerky steps of about 150 feet. Steps occur at about 50 microseconds intervals. In its wake it leaves an ionized glowing trace, with forks where other streaks have branched off. During each step, the stepped leader is in search of the opposite polarity charge traveling by the shortest and easiest path. Sensitive cameras have recorded these glowing traces, which are not visible to the eye. As the stepped leaders near the ground, oppositely charged streamers extend upward to meet the descending leader. All these streams are from the building-up of static electrical charge which not only flows over metallic conductors but almost as well over the surface of anything. The streamers extend upward from buildings, trees, grass; everything including the overhead electric lines. The overhead lines (with the exception of trees and buildings in urban areas) are the tallest objects around. Therefore the ascending streamer from the overhead lines would normally contact the descending stepped leader first. The stepped leader takes its last step, following the streamer to the line.

Then the main event begins. The negative charge which the stepped leader has deposited at various steps along its path is short circuited or "dumped" on the line. The last step is dumped first; then the next higher, etc., progressing up to the cloud. Since the dumping begins at the bottom and progresses upward normally, it appears that the stroke races up from earth to the cloud. This dumping is accompanied by intense light along the traces and branches left by the stepped leader. This is called the return stroke. It travels at 300 feet per microsecond or 200 million miles per hour and takes about 40 microseconds to reach the cloud.

Some descriptions of the return stroke are in terms of current instead of movement of negative charge (electrons). Since the direction of conventional current is opposite that of the movement of electrons, the difference is a change in direction of movement of the return stroke. In terms of conventional current, the return stroke would move up from the line to the cloud.

Streamers and leaders are also at work within the cloud. A return stroke may occur between the top and bottom of the thunderhead. As a matter of fact, the majority of strokes are within the cloud. These are cloud-to-cloud strokes as opposed to cloud-to-ground strokes.

The return stroke may be the end of the flash. However, if conditions are right, the main trace route could be re-ionized about 40 milliseconds later. This also appears as a light with the same intensity as the stepped leader, traveling at about 6 feet per microsecond or 4 million miles per hour. This is referred to as a dart leader. When it hits the overhead line, another charge dumping process takes place, and we have another brilliant return stroke along the same path. This can be repeated many times. As many as 26 return strokes, or "multiple strokes" have been recorded in one flash. This has also been referred to as the multiplicity rate. A lightning flash may have one or more individual lightning strokes but to the eye only one flash can be seen. Hence they are referred to as a lightning "flash" and a lightning "stroke".

Not all surges caused by lightning are direct strokes to the line. When a cloud whose bottom is negatively charged is directly over the line, the electrons in the line in the vicinity of the cloud are repelled and flow out of that part of the line, leaving it positively charged. The charge becomes greater as the stepped leader approaches. If the stroke occurs to a nearby object rather than to the line, the line is abruptly left with an excess positive charge. The electrons which were driven from the vicinity of the stepped leader will surge back to equalize this charge. Moving charge is current so we suddenly have a current surge, moving away from the point under discussion. This current, flowing through the line surge impedance, creates a voltage surge. This type of surge is called an "induced" stroke. These surges are not as significant as the surges caused by direct strokes, but will cause failures of unprotected equipment.

D. PREVENTION OF LIGHTNING DAMAGE TO EQUIPMENT

Lightning will splinter wood poles and wood crossarms. But only in rare cases will enough damage be done by lightning to warrant a replacement. Lightning by itself typically does not cause extensive damage to company's facilities. The problem is that lightning has sufficient voltage to flashover the insulation used for distribution. Then the power follow current (60 Hz current) will keep the flashover arc established until it is interrupted. This current is much more destructive than the lightning. It can flash-burn porcelain, melt conductors and ignite fires in wood. FPL's breaker relaying and fuse coordination greatly reduces the probability of this type of damage. All primary equipment subject to surge damage is protected with surge arresters. With them, surge voltage on the equipment is held to the discharge voltage of the arrester plus the voltage developed in its leads by surge current.

In 1930, transformer and equipment manufacturers met with utility engineers to form a joint committee on insulation coordination. Ten years later they had set up a table of insulation levels to which the manufacturers now produce and verify by test. These insulation levels were standardized for the different operating voltages. This is referred to as the Basic Insulation Level or BIL (it is now defined as Basic Lightning Impulse Insulation Level). The standard BIL's used for FPL's distribution transformers and discharge arrester voltage are:

Operating Voltage	Basic Insulation Level (BIL)	Arrester Rating	Discharge Voltage+
2.4/4 kV	60 kV	3 kV	12.0 kV
7.6/13.2 kV	95 kV	10 kV	37.5 kV
13.2/23 kV	125 kV	18 kV	70.0 kV

+Crest value of a 20,000 ampere, 8 x 20 microsecond wave. It has been estimated that only 1% of the distribution surge arresters will experience 21,000 amperes or more.

You will note the arrester discharge voltages are well below the BIL. Of course it must be kept in mind these voltages were obtained in a laboratory with waves which are considered average. A shorter time to peak, for instance, would cause a higher discharge voltage.

E. VOLTAGE DOUBLING

Another problem is voltage doubling. This occurs at an overhead deadend or the terminal end of radial (or open switched) cable. The voltage surge acts similar to a wave of water in a pool. If the water wave hits the pool wall, the height of the wave increases near the wall. This same thing happens with a voltage surge at an open point. The electric surge, having a steeper wave front, will double on itself. If there is no arrester at the open end, a surge limited only by an arrester elsewhere could double at the open end on the 2.4/4 kV systems and 7.6/13.2 kV systems without exceeding the BIL of the equipment. In the case of the 13.2/23 kV systems, the surge voltages will double to over 140 kV. With a BIL of only 125 kV, there would probably be an insulation flashover in the equipment. For this reason, 13.2/23 kV underground is the only operating voltage which requires an arrester at the open end of the cable.

F. INSULATION DETERIORATION

Insulation in equipment is made up of oil, paper, cloth (tapes), plastics, etc. FPL or any electric utility purchases equipment with a specified minimum BIL. As the material used for insulation ages, the BIL also deteriorates. Heat can also be a factor in the reduction of the BIL. When transformers are operated above the design temperature (FPL purchases with a design of 65E C rise over ambient) the insulating strength will weaken at an accelerated pace. It has also been found that the transformer BIL is reduced during the time when it is operating at a higher temperature than it was designed for. Transformers fail most often during thunderstorms. Lightning is charged as the cause. But is it? Many factors contribute to the deterioration of transformer insulation and subsequent failure. In many cases the lightning may have been only a "triggering" factor, rather than the basic cause. FPL standards require a surge arrester to protect equipment from these surges. A few points should be emphasized. An arrester should be "close coupled" to the device it is protecting. Long arrester leads will add on the average 6 kV per foot of lead. The device will be subjected to this voltage in addition to the discharge voltage of the arrester. Low resistance grounds improve the performance of the surge protection. Damaged or disconnected arresters should be replaced as soon as possible. Obsolete arresters should be replaced whenever there is work on the pole. (See Section 3.6.1.)

G. LIGHTNING PROTECTION OF OVERHEAD LINES

Ben Franklin probably saved thousands of buildings through his invention of the lightning rod. What a simple idea: To intercept the lightning stroke before it hit the building and provide a path to ground. Basically this is what is done by FPL or any other utility. The problem when dealing with power lines is to shunt the lightning surge to ground and yet prevent the electric power from being shunted with the surge. The insulation for the overhead primary line should prevent the flashover of the majority of lightning surges. Not only is the porcelain considered in the insulation but also fiberglass and wood. FPL standard pole framings provide a BIL of about 350 kV for tangent poles. 138 kV transmission tangent poles have about 900 kV BIL. Distribution deadends are designed to have about 500 kV BIL, transmission deadends about 1360 kV BIL. All the BIL voltages quoted are for a negative impulse which is the same as most lightning surges.

1. Overhead Ground Wire Protection

An overhead ground wire should be used for the lightning protection of FPL's distribution system when direct lightning strokes are prominent. Like the lightning rod, the overhead ground (or shield) wire intercepts the lightning stroke, and the pole ground shunts the lightning surge to ground. This will eventually happen, but from the time the surge reaches the pole until it is dissipated, voltage is built up on the pole in proportion to the surge current. The possibility of the surge causing a flashover to the phase conductor is excellent. To prevent this, two things can be done. First, more insulation should be used between the pole ground wire and the phase conductor. This is accomplished with standoff fiberglass pole ground wire brackets, more wood and additional porcelain insulation. Second, the driven ground rod must have as low a resistance as possible. A 10 ohm driven ground rod at each pole is recommended.

2. Surge Arrester Line Protection

Refer to Section 3.6.1, this manual, for a complete discussion of surge arrester theory and design.

Surge arresters are used to protect FPL's distribution overhead lines where induced lightning strokes are most prominent. FPL has been the pioneer in this method of protection. It originally started with attempts to raise the BIL to help reduce lightning flashovers. An additional disc insulator was added to primary deadends to make a total of three. Fiberglass was used as guy strain insulators for all guys above the neutral and for replacing the steel crossarm brace under "B" phase. Then "armless" or "triangular" construction became the vogue. Since the overhead ground wire worked so well for transmission, why not try it on distribution? Several lines were built this way, but they were limited to rural areas. The triangular construction was used in urban areas. It had "B" phase in the top position. This phase was used as an overhead shield wire by providing the surge a path to ground about every 800 feet through an arrester. Failures of the two side insulators, "A" and "C" phases, began to happen with this protection scheme. The obvious correction was to use surge arresters on all three phases. About this same time, FPL entered into a study with seven other utilities and General Electric. The results of this study gave us the answer to the failures of the "A" and "C" insulators. A conductor with a surge, which has a voltage of 186 kV or greater per foot of distance to an adjacent conductor, will have streamers form between these conductors. Electrons will actually flow from the conductor with the surge to the adjacent conductor through the streamers. This is called "predischarged currents". If the voltage per foot could build up there would be a flashover or discharge. The electron flow reduces the current in surged conductors but adjacent conductors will now have a surge. This will have the effect of lowering the voltage between adjacent conductors and preventing midspan flashovers. However, trouble arises when all these surges encounter a pole. Each surge on every conductor will attempt to flashover its insulation to the grounded pole. Therefore, arresters on all three primary conductors will provide a controlled path to ground for the surges, preventing the flashovers. FPL recommends maximum spacing for these arrester stations according to the number of phase conductors, type construction and the material of the pole. A reduction in the effectiveness of one of these factors must be compensated for by an increase in effectiveness of one or more of the others if the same degree of lightning protection is to be maintained. For this reason it will be seen that maximum spacings between surge arresters will vary with changes in basic insulation levels and line configuration (see Table I). This will provide the same level of lightning protection for each type of construction listed.

It may be decided to increase the protection on certain specified feeders or at certain locations where unusual problems exist. This is easily done by decreasing the arrester station spacing.

3. Comparison - Overhead Ground Wire Vs. Surge Arresters

Any kind of lightning protection scheme is much better than none at all. Careful comparison of the advantages and disadvantages of each type is the only way to determine their relative effectiveness.

Installing arresters on only the top phase (where conductors are framed triangular or vertical) is uneconomical. Approximately 2-1/2 to 4 times as high an insulation level would have to be used on the other two phases to get the same protection. Obviously, 138 kV insulators would not be acceptable from a cost or appearance standpoint.

Use of an overhead ground wire is a practical approach only when high BILS can be maintained, little or no natural shielding exists and direct lightning strokes are a problem. This would require 69kV insulated standoff brackets for the pole ground to maintain BIL on wood. A low ground resistance is required at all poles. Arresters would still be required to protect all equipment.

When all is considered, the FPL protection method is determined by the lightning activity in distribution construction area.

4. Application Of Arresters For Line Protection

Basic Insulation Level (BIL) is the measure of a line's ability to withstand rapidly rising surge voltages, such as result from lightning strokes. It is provided by porcelain, wood, fiberglass, air or combinations of these. Obviously, therefore, with the same insulators a line built on wood poles will have a higher BIL than one built on concrete poles, unless the insulator bases are grounded on the wood poles. This results in shorter spacings between arrester locations on concrete pole lines than on wood pole lines.

BIL is also affected by pole framing. For example, where the primary is framed on wood crossarms, if the neutral must also be carried on the arm, this reduces the BIL to the point where it should be treated the same as a steel arm on a concrete pole.

Surge arresters used for line protection are to be applied to each phase conductor at each arrester location, regardless of the configuration of the line, and with the following recommended maximum spacings between locations. These spacings are meant to be used as a guideline for standard construction. Local field conditions and sound engineering judgement, as always, will dictate how strictly to adhere to these recommendations:

Type	Construction	Type Pole	Recommended Maximum Spacing - Ft.	Recommended Maximum Spacing - Ft. From Deadends
3ø	Triangular	Wood	600	300
3ø	Triangular	Concrete	400	200
3ø	Vertical	Wood	800	300
3ø	Vertical	Concrete	400	200
3ø	Modified Vertical	Wood	800	300
3ø	Modified Vertical	Concrete	400	200
3ø	Crossarm	Wood	500	150
1ø	(Any)	Wood	600	150
1ø	(Any)	Concrete	200	150

Spacings on wood poles with grounded hardware are the same as shown for concrete poles. Spacings on 2ø lines are the same as shown for 3ø lines.

TABLE I

NOTES:

26. The opportunity should be taken to gradually bring existing lines up to these new standards whenever major maintenance work is done, such as reframing, reconductoring, or the relocation or replacement of several adjacent poles, or if the line has a history of lightning-related service unavailability which is above acceptable levels.

153. Although the above table allows separation between arresters and deadend poles, the arresters should be placed at the deadend whenever this is possible. This is especially important where steel arms are used. It should be noted, however, that the term "deadend" applies here only to an electrical termination, and does not include corner or junction poles or double deadends that are jumpered across. Furthermore, arresters should be installed on both sides of disconnect switches, at the switch pole or on adjacent poles, with spacing from switches to arresters no more than 150 feet where possible. Where switch bases are grounded (brackets mounted on concrete poles are considered grounded) every effort should be made to install arresters on the switch pole. An exception is feeder riser poles where the switches are normally closed, and would be open only for emergency repairs. In this case, arresters on the pothead bracket provide protection for the switches.

The ground lead from every arrester must be connected to a driven ground of not more than 25 ohms resistance. As DCS Section G now states, further reduction to 10 ohms is desirable if this can be accomplished without using more than 40 feet of rods.

Distribution circuits built on wood crossarms on wood transmission poles require surge arrester line protection only if pole-ground standoff brackets are not installed down to a point below the distribution conductors. Where the distribution is framed on steel crossarms, their lack of impulse insulation strength must be compensated for by an increase in protection. It is strongly recommended that surge arresters be installed in accordance with Table I wherever steel crossarm construction is used. Equipment such as transformers and disconnect switches must always be protected by arresters.

Distribution circuits on concrete transmission poles should be protected with arresters the same as if the transmission were not there. In this case the distribution insulator bases and hardware are grounded, resulting in a BIL of low enough magnitude that surge currents flowing from overhead ground wire to ground could cause the distribution insulators to flash over if not protected. On rare occasions, it may be necessary to build a double-circuit line - that is, one three phase circuit above another on the same pole line. In such a case, the top circuit will in general shield the bottom circuit; however, there are precautions that must be observed. If wood crossarms or post insulators on wood poles are used, then at any pole where the pole bond is extended up past the lower circuit (as at an arrester station for the top circuit) the BIL of the lower circuit will be lowered. At such a pole, it will be necessary to frame the pole bond wire on standoff brackets, or to install arresters on the lower circuit. If concrete poles are used, or if steel arms are used on wood or concrete poles, arresters will be required on the top and bottom circuits alike, due to the reduced BIL. At deadends, with any type of construction, arresters must be installed on both the top and bottom circuits.

Protection of 3 phase corner poles should be by installing arresters at adjacent poles retaining maximum spacings per Table 1.

5. Application Of Arresters For Equipment Protection

Surge arresters are installed on the FPL system to protect the equipment listed below. For details and/or drawings, refer to the listed information sources.

Primary Risers - see DCS Section C.
Disconnect Switches and Reclosers - see DCS Section C.
Pole-mounted Line Regulators - see DCS Section I.
Pole-mounted transformers - see DCS Section I.

S&C and McGraw Edison sectionalizing switches – see DCS C-11 & C-12.
URD Three phase Pad mounted Switchgear – see DCS C-26 and DERM Section 5.5.1, p. 13.
Open points on 23 kV URD loops – see DCS I-65A and DERM Sections 5.3.4, p. 5, and 5.5.1, p. 13.

In addition, there are 650 V arresters which are applied as follows:
In stacked vaults - see DERM Section 5.8.2, p. 7.
On overhead 480 V street light circuits - see DCS Section H, and DERM Section 6.4, p. 21.

Arresters installed for protection of equipment such as pole-mounted transformers may also be considered as a line protection location, provided that an arrester is installed on each phase, and provided that the leads can be short enough to offer effective protection. It must always be borne in mind that the degree of protection decreases as the length of the jumper between line and arrester increases. Long leads have an extremely high impedance to lightning strokes, increasing as the steepness of the wave front increases; therefore, if the leads are long, a high-magnitude surge with a steep rate of voltage rise can result in destructively high surge voltages on the line, even though perfectly good arresters are connected to it. Arresters must always be coupled as closely as possible to whatever they are intended to protect.

Arresters installed on riser poles (see DCS UH-50 for an example) may be connected on the load side of fuse switches. In this case, a lightning surge must travel through the fuse link before reaching the arrester. Very likely, the fuse will blow, especially if it is rated 25 k or smaller. Aside from the obvious nuisance, the arrester protection on one or more phases is lost for the duration of the outage.

Disconnect or fuse switches on riser poles may be left open for various reasons. While they are open, the arresters are disconnected, eliminating whatever line protection they might have provided.

For these reasons, it is usually unwise to depend upon riser-pole arresters to protect the overhead line conductors. However, if there happen to be several riser poles in a section of line, the marginal protection provided by each may well add up to good protection for the line. In general, existing line arrester stations should not be removed just because several riser poles are installed, unless there is a compelling reason to do so.

It must also be pointed out that the arresters accompanying several single or two phase riser poles or several single transformers or open-delta banks do not add up to the same protection provided by a three phase line arrester station, even if they all are on adjacent poles. To understand why this is true, consider a case such as is shown in Figure 1. Each pole has a single transformer. One Pole No. 1, the transformer and arrester are tapped to A phase, on Pole No. 2 to B phase, and on Pole No. 3, to C phase. A lightning surge traveling from left to right reaches Pole No. 1; the arrester operates and discharges the surge to ground on A phase only.

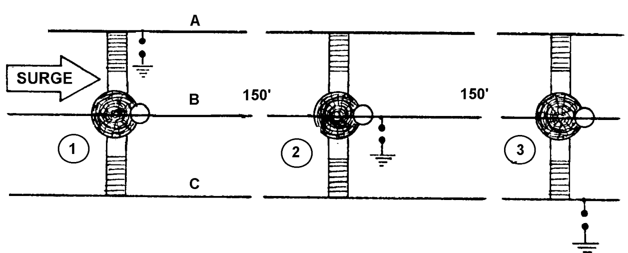


Figure 1

There is still a high surge voltage on B and C phase, which continues on to Pole No. 2, where B phase arrester operates. At this point there is still a high surge voltage on C phase. Under these conditions, it is likely that there will be a flashover between A and B phases between poles 1 and 2, or between B and C phases between poles 2 and 3.

To put it another way, it might be considered that we have an arrester with normal lead length on A phase, one with a 150 ft. primary lead on B phase, and one with a 300 ft. lead on C phase, as far as this lightning surge is concerned.

One or two general reminders: As has been said before, arresters for equipment protecting must be placed as close as possible to the equipment. Leads must be as short as possible in order to minimize the impedance of the ground path. However, the ground lead must be long enough to permit the ground-lead disconnector to separate in the event of arrester failure. See DCS Section G, for additional details.

Ground leads on pole-mounted arresters can cause other problems. If the lead is trained too close to the ungrounded L-bracket, as shown in Figure 2, radio and TV interference is likely to result. The ground lead must be two inches or more from the bracket.

Figure 3 shows a case where the L-bracket is bonded to the pole ground, as it should be in a salt spray area, and the arrester ground lead is bonded to the bracket. This arrangement not only adds two connections - and more resistance - into the arrester circuit, but it also violates the National Electrical Safety Code, whose rules state that hardware is never to be a current-carrying part.

The correct installation shown in Figure 4 is neat and workmanlike, and makes it easy to have a proper - and visible - separation of the ground-lead disconnector in the event of arrester failure. The arrester, of course, needs to be positioned so that the disconnected ground lead can not swing into any energized part.

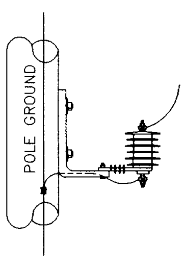


Fig. 2 (WRONG)

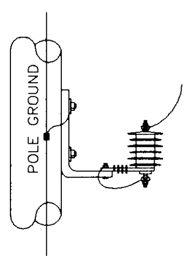


Fig. 3 (WRONG)

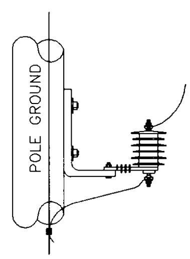


Fig. 4 (CORRECT)

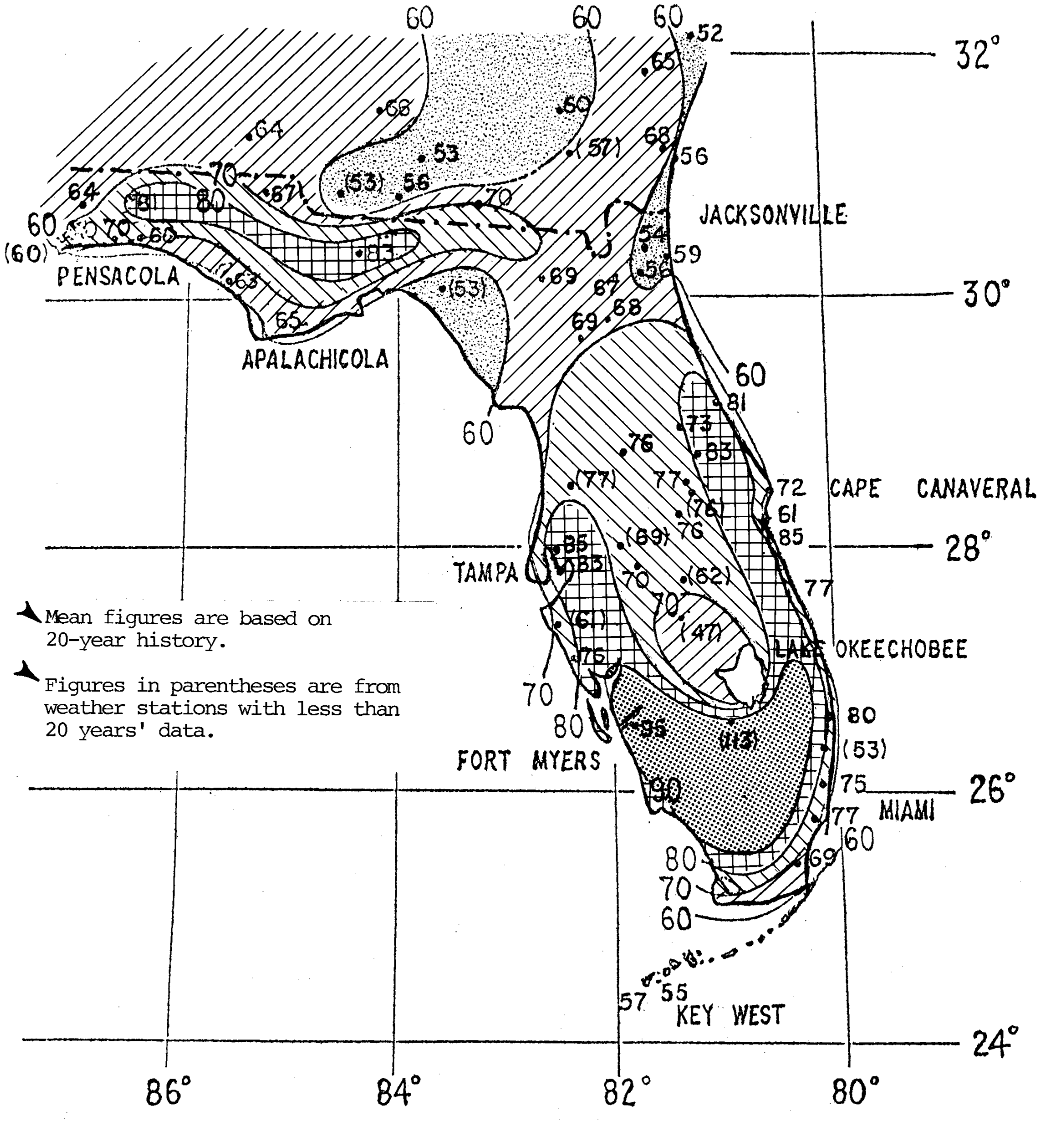


Figure 5 - Mean annual thunderstorm days for the State of Florida.

H. ADDITIONAL REFERENCES

T&D Trade Magazine, September 1976, "Surge Protection for Distribution Systems".

Westinghouse Transmission and Distribution Reference Book, Chapter 16, "Lightning Phenomena".

IEEE, Transactions 69 TP 91 and 92 - PWR, "Investigation and Evaluation of Lightning Protective Methods for Distribution Circuits".

ANSI C62.22 - Guide for Application of Metal-Oxide Surge Arresters for AC Systems - 1997

2.9.2 FERRORESONANCE

A. GENERAL

A condition called "ferroresonance" may sometimes occur on a portion of a high voltage distribution system. It can cause high transient or sustained overvoltages on isolated parts of three-phase distribution systems. This condition can result in damage to transformers, cables, terminators, surge arresters, or other equipment. The most common occurrence is operation of the ground disconnect device on surge arresters.

As an example, a bank of 2 - 37-1/2 kVA and 1-50 kVA transformers in closed wye-delta configuration and located behind the building being served. It is fed from an overhead line on the front of the street by an aerial cable lateral. The cable consists of 3-1/C #2 rubber insulated shielded 15kV cables operating at 7.6/13.2kV. The length of cable is approximately 250 feet. The fuses are at the junction of the aerial cable and open wire line on the street. An attempt is made to put it into service by closing one fuse switch at a time. When the first switch is closed the surge arresters on the other two phases failed. They are replaced and the same thing happened again. A set of fuse switches were installed at the transformer bank pole and were used successfully to put the bank in service.

1. Definition

Ferroresonance is caused by the relationship of the capacitive reactance of the cables, the overhead line or transformer bushing and winding to the magnetizing reactance of the transformer. Since the magnetizing reactance of a transformer varies over a wide range because of the non-linear magnetization curve of iron, ferroresonance is likely to occur under certain system conditions.

2. Theory

Ferroresonance is similar to the resonant condition that occurs in a simple series RLC circuit like the one shown in Figure 1.

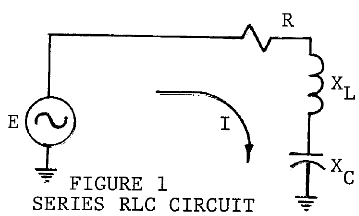


FIGURE 1
SERIES RLC CIRCUIT

The current (I) in this circuit is defined by the following equation:

$$I = \frac{E}{\sqrt{R^2 + (X_L - X_C)^2}}$$

The series RLC circuit becomes fully resonant when the magnitude of the inductive reactance (X_L) equals the magnitude of the capacitive reactance (X_C). Under this condition, the current is limited only by the resistance (R), and becomes very large if R is small. However, this current still flows through the inductor and capacitor and develops large voltages across them.

The relative inductance and capacitance of a typical distribution system are such that ferroresonance is not likely to occur under normal operating conditions. An unbalanced condition which may result from a blown fuse or single-phase switching is more likely to initiate the ferroresonant state. The overvoltage condition appears on the open phase or phases on the load side of the open switch, and is sustained until all three phases are either open or closed. This overvoltage condition is often evidenced by an unusually loud transformer hum.

When a flashover or arrester failure does occur on the open phase, the fuse on the closed phases usually will not blow. This is because the current is limited by the resistance of the transformer primary winding.

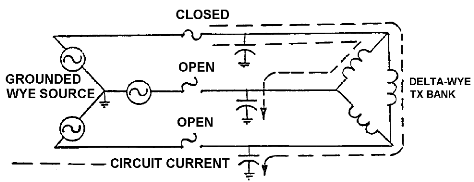


Figure 2

Figure 2 shows a section of a typical distribution system where ferroresonance can occur. A three phase delta-wye transformer bank is fed from a grounded wye source through an underground lateral of three single conductor concentric neutral cables. The transformer is unloaded and only one phase is energized. Only the most significant parameters that contribute to ferroresonance are shown. The arrows show how it is possible to have a series LC circuit that may result in a ferroresonant state. The analysis of this circuit is similar to that of the series RLC circuit previously discussed.

3. Effect of Transformer Connections

Certain transformer connections are more subject to establishing ferroresonant overvoltages. In general, ferroresonance is more likely to occur when ungrounded primary transformer connections are used. Grounded primary transformer connections help to avoid it. The transformer ground shorts out the cable capacitance. This reduces the probability of having a series LC circuit that is likely to become ferroresonant.

Table I shows several transformer connections fed from a grounded wye source and their susceptibility to ferroresonance. The arrows show the path of a series LC circuit from the energized phase of phases to ground when one or two phases are open.

4. Effect of Transformer Loading

Transformer loading affects the probability of ferroresonance. Usually, if the transformer is loaded to four per cent or more of its rating ferroresonance is not likely to occur. The load impedance is reflected into the primary circuit, lowering the inductive reactance, and the resulting RLC circuit is not likely to become ferroresonant. The inductive reactance must be very high to resonate with the normally high capacitive reactance of cables and overhead lines.

TABLE I

TENDENCIES OF VARIOUS TRANSFORMER CONNECTIONS
TOWARD FERRORESONANCE

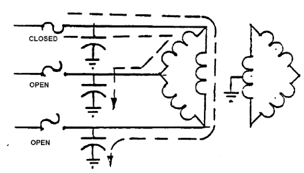
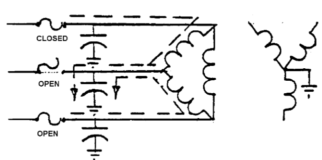
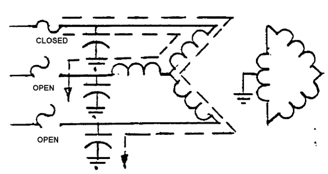
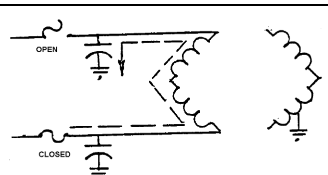
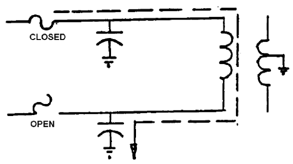
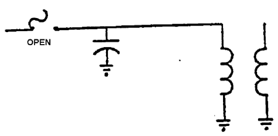
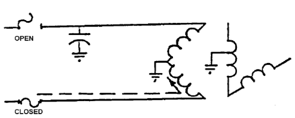
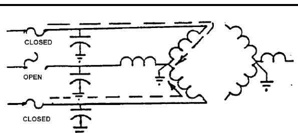
- - - - CIRCUIT CURRENT CIRCUIT DESCRIPTION	FERRORESONANT OVERVOLTAGE PROBABILITY	REMARKS
	Possible	Delta-delta bank - One or two open phases produces series LC circuit from energized conductors through transformer reactance in series with cable capacitance to ground.
	Possible	Delta-wye bank - One or two open phases produces series LC circuit from energized conductors through transformer reactance in series with cable capacitance to ground.
	Possible	Wye-delta bank - Ungrounded primary neutral. One or two open phases produces series LC circuit from energized conductors through transformer reactance in series with cable capacitance to ground.
	Possible	Open delta-open delta bank - One open phase. One open phase produces series LC circuit from energized conductor in series with cable capacitance to ground.

TABLE I (CONT'D)

	FERRORESONANT OVERVOLTAGE PROBABILITY	REMARKS
	Possible	Single-phase - Transformer connected phase-to-phase. One open phase produces series LC circuit from energized conductor through transformer reactance in series with cable capacitance to ground
	Unlikely	Single-phase - Transformer connected phase-to-ground. Open phase de-energized transformer winding.
	Unlikely	Open wye-open delta bank - Transformer ground shorts out the cable capacitance.
	Unlikely	*Grounded wye-grounded wye bank - Transformer ground shorts out the cable capacitance.

* Three-phase transformers have four-legged or five-legged or five-legged cores to avoid tank overheating during unbalanced conditions. The magnetic coupling between the primary windings established a complex circuit that may cause low magnitude ferroresonant overvoltages. distance from transformer bank to transformer fuse can be approximately 15 times the values shown in Table II to avoid ferroresonance.

5. TNA Study

Since a mathematical analysis that includes all the parameters of a three-phase distribution system is very complex, there still exists a high degree of confusion concerning ferroresonance. A system simulator called Transient Network Analyzer has been very helpful in studying ferroresonance. The TNA can be set up with the system parameters and system operations such as single-phase switching or fuse blowing can be simulated. The resulting ferroresonant overvoltages can be monitored with an oscilloscope. The cable (or overhead line) is the major source of capacitive reactance that contributes to the ferroresonant condition. In some cases, the capacitive reactance of small transformers used in our 23kV system is sufficient to cause ferroresonance. Table II shows the maximum distance from transformer fuse to the transformer to avoid unacceptable overvoltages on open phase conductors feeding wye-delta and delta-wye installation on our 13kV system. We have experienced satisfactory operation by limiting this distance to the values shown in the table. This table was developed with the help of TNA studies and using the parameters of the equipment used by Florida Power & Light Company. Though not shown in the table, ungrounded banks of potential transformers are subject to ferroresonance because of their small size.

B. DESIGN CRITERIA

1. New Installations

a. 13 kV System

On our l3kV system, transformer connections that are likely to cause a ferroresonant condition should be avoided. See Table I. If they are used, the distance between the transformer bank and the transformer fuse switches must be limited to the values shown in Table II. If there is more than one bank on the load side of the fuse switch, use the total kVA of all banks to determine allowable distances to the most remote bank. If one transformer of a bank is larger than the other two, assume the bank to be three of the large size transformers.

Ferroresonance is not likely to be troublesome on a 7.6/13.2kV 3Ø URD Loop with closed wye-delta banks. The transformer fuses are usually in the same vault with the transformer bank, resulting in short cable sections. In addition there are usually a number of banks connected. This increases the effective size of the bank when using Table II. If an end vault is isolated from the loop and must be energized by single phase switching, Table II governs. If the bank is lightly loaded, ferroresonance may occur. This may be prevented by opening the switch or fuses at the transformer before energizing the cable to feed that vault. The transformer fuses may later be closed.

b. 23 kV System

On our 23kV system, transformer connections that are likely to cause a ferroresonant condition must be severely restricted. Ferroresonance is more likely to occur, as transformer exciting reactance is higher and more nearly matches the capacitive reactance to ground of cables or overhead lines. Transformer magnetizing reactance is approximately three times as great on the 23kV system as on the 13.2kV system. Cable shunt capacitive reactance is about 16% greater on 25kV cable than on 15kV; OH line shunt capacitive reactance is about the same. Therefore, to use Table II for our 22.9kV system, allowable cable lengths should theoretically be multiplied by 0.35 and O.H. line lengths by 0.33. From a practical, "ease of application" standpoint, divide all lengths by 3.

Depending on internal winding and bushing capacitance, 13.2/22.9kV Wye-delta and delta-wye banks of three transformers 25kVA each or smaller, may experience ferroresonance with the fuses located at the transformers. When small new three phase loads requiring one of these banks must be served from the 23 kV system, a wye-wye or an open-wye, open-delta bank should be used, even when on open wire lines.

When picking up the isolated end vault of a URD loop which has a closed wye-delta bank, the procedure discussed above for the l3kV system may be used.

TABLE II

MAXIMUM DISTANCES FROM TRANSFORMER FUSE
TO TRANSFORMER TO AVOID UNACCEPTABLE
OVERVOLTAGES ON OPEN PHASE CONDUCTOR(S)
ON 7.6/13kV WYE-DELTA AND DELTA-WYE BANKS*

Distance in Feet, Transformer to Open Fuse

Bank Size			Cable			Open Wire
kVA	#2 PE	#1/0 PE	#3/0 PE	#3 PILC	#1/0 PILC	#1/0 & Smaller
3-37½	50	45	40	30	25	400
3-50	80	75	60	50	40	770
3-75	110	100	90	70	55	1,700
3-100	160	150	130	110	80	3,400
3-167	280	255	220	180	135	6,900
3-250	540	490	420	350	255	14,800
3-333	755	690	590	490	360	21,500
3-500	1,075	980	840	695	515	31,300

*Note: For our 23kV system, divide allowable cable and open wire lengths by 3.

When you must use a bank susceptible to ferroresonance, you should consider a three-phase recloser or other three-phase protective device. However, these are more expensive and require more maintenance than fuses.

2. Existing Installations

Corrective modifications will not be made to existing installations except when other major work is being performed, or problems with ferroresonance have actually been experienced. Corrective action should follow the guidelines for new installations. Usually, the most economic solution is changing the transformer installation to one that is not likely to cause ferroresonant overvoltages. See Table I.

C. REFERENCES

The following is the DEO bulletin that was published in 1997.

DEO BULLETIN

Florida Power and Light Company
March 14th, 1997
Bulletin # 9701

To: **All Holders of the Distribution Construction Standards**

Subject: **Three phase padmounted transformers may experience ferroresonance, while first energized.**

Ferroresonance is an overvoltage phenomenon that sometimes occurs with primary voltages of our distribution system. In transformers, it is more common at higher primary voltages (23Kv) due to the higher magnetizing reactance of the transformer. Ferroresonance is caused by a mutual interaction of the capacitive reactance of the primary source cables and the magnetizing reactance of the transformer being energized.

Although not as common with three phase transformers, ferroresonance may be present whenever the applied transformer load and connected primary cable lengths are critical for this condition . Ferroresonance is predominant whenever a lightly loaded transformer is energized at a distant remote switching point. Energizing a transformer with loads less than 15% of the transformer's rated capacity and cable lengths larger than those shown on DERM 2.9.2, page 5, may cause a ferroresonance effect.

A ferroresonant effect on three phase transformer installations can be identified and categorized by arcing of the terminations at the switch point as the phases are individually energized. During this process, the transformer will experience secondary voltage fluctuations with internal arcing in the transformer coil.

Once this condition is first experienced at an initial transformer installation the energizing procedure should not be continued. Transient overvoltages present with ferroresonance may cause damage to the transformer, cables and terminations involved.

To reduce the likelihood of a ferroresonant condition , the capacitive reactance of the cables or the inductive reactance of the transformer needs to be minimized. This can be accomplished by either increasing the load on the transformer or energizing the transformer with the bay-o-net fuses at the transformer location. Since an immediate increase in load is not commonly possible, it is suggested that a ferroresonant condition be mitigated by having the transformer energized with the bayonet fuses at the transformer location.

If you have any questions regarding this bulletin please contact Miguel Valbuena in Distribution Engineering at (561) 845-4833.

David Phillips

D.A. Phillips
Manager,
Distribution Engineering Support Services

2.9.3 RADIO AND TV INTERFERENCE

A. GENERAL

1. Objective

The objective of this section is to create an awareness of the basic nature of Radio Interference (RI) and Television Interference (TVI) on power line circuits and the precautions that should be taken in design and construction to minimize it.

It is not the intent to train you as an interference locator nor to fully describe interference locating equipment. Under "Other References" we have listed an IEEE Tutorial Course. We would recommend the purchase and use of this course if you need to go beyond what is contained in this section.

2. The General Nature of RI and TVI

At the present time, all generally available radios and TV sets receive either amplitude modulated (AM) or frequency modulated (FM) signals, or both. Radio and TV interference originating on power lines is amplitude modulated, (AM) and therefore interferes only with AM radios and with the video (picture) circuits of TV sets. The detector in an FM radio receiver or in the audio section of a TV set chops off the changes in amplitude and is only sensitive to (demodulates or detects) changes in frequency.

The two basic causes of RI and TVI on a power system are corona and gap discharge. These two phenomena produce electromagnetic energy which is in the radio frequency range. It is radiated from the line into surrounding space, and is also conducted along the line. The line conductors and the earth become transmission lines and wave guides for the high frequency currents and voltages accompanying the electromagnetic energy. Several different modes of transmission can exist at the same time.

B. CORONA

Under certain conditions, corona may appear on transmission and distribution systems whose design was intended to make corona impossible. Dust or moisture droplets may change the smooth conductor surface to a rough surface which produces corona at the irregularities. Corona usually occurs during the peak of the voltage curve, once per cycle on the positive peak and once per cycle on the negative peak. Corona as we know it is a partial discharge into the air due to breakdown of the dielectric adjacent to a conductor in the presence of high voltage stress. Complete breakdown to earth or to another conductor does not occur. Corona discharges are pulsative, not continuous, during the peak part of the AC wave on conventionally designed transmission lines. If the voltages were a great deal higher for the same design parameters, the corona could become continuous over the peak part of the voltage wave and the line would be near complete breakdown. The frequency spectrum of RI and TVI caused by corona is usually confined to an upper limit of 30 mHz. This is because of the wavefronts of corona pulses are not very steep.

Corona does not usually occur around distribution conductors or fittings. However, sharp points on the ends of conductors, pieces of fine tag wire left on a conductor or switch blade, or any sharp irregularity may create enough voltage stress to cause corona. Most of the time, if corona is found to be the source of a complaint, it will be located on circuits above 23 kV.

Wave guide modes of transmission on a three phase line for interference from corona or gap discharge are (a) between conductor and ground; (b) between the two outside conductors; (c) current flow in one direction along the two outer conductors and in the opposite direction in the center conductor. Because of losses in the ground, the signal being carried by the phase to ground mode is rapidly attenuated. At frequencies in the AM broadcast band (540 to 1,600 kHz), this signal is attenuated in just a few miles. The signal carried in the modes employing only the conductors will be carried many times as far. Measured in a lateral direction from a line, there is a canceling effect on radiation from the currents in the various conductors and the signal strength drops quickly. Interference due to corona is usually worse during light rain and when contamination has collected on the line. This is known as "foul weather" interference.

C. GAP DISCHARGE

Gap discharge interference is the most prevalent type of interference on distribution lines, and is also troublesome on transmission lines.

Gap discharges can occur in power-current carrying circuits. Loose or corroded connectors, loose switch blades, transformer terminal connections or customers' fuses are a few examples. This type of trouble is relatively easy to spot and correct, since it causes lights to flicker, heat at the loose connection, and a voltage drop. All of these effects are clues which will help locate the source of the trouble.

There are many gap discharges which do not affect the operation of the circuit, but do cause RI and TVI. These are outside the normal flow of power current.

Every isolated body has capacitance, and is capable of accepting a charge if a source of potential difference is applied to it. If a conductor from a circuit having a high enough potential difference is brought close to the uncharged body, the insulation will break down and charge will flow into the body. An arc has thus formed across an air gap. Current flowing into the body raises its potential to that of the source circuit, so the arc is extinguished. The body then begins to lose this charge. If the applied voltage is alternating, the source voltage reverses the polarity of the source side of the gap. The body may be still partially charged to opposite polarity. The gap will break down again and this will continue, two arcs per cycle being created. The amount of current flow is small, but is oscillatory, the frequency range depending on the natural resonant frequency of the circuit. The discharge is a damped wave so a wide range of frequencies will be present. Gap discharge radiation will interfere with both radio and TV AM signals and will extend into AM bands above the TV frequency bands. A radical example of this type of discharge would be from a primary conductor to a tie wire through a layer of corrosion; or from a weatherproof primary conductor to a tie wire. Other examples are loose connectors allowed to slide out into the span and not removed, or pieces of wire thrown over the line.

The source of voltage or potential difference needed to cause the arc is not always evident. What could be more innocent, from an interference standpoint, than the metal staples holding a pole ground wire in place? The wire is at ground potential and the staples are not energized; or are they? If there is a leakage or capacitive current flow from line to ground, the pole becomes a voltage divider resistor. Being embedded in the pole, the staples receive a proportionate part of line voltage. If in tight contact with the pole ground wire, they are forced to be at ground potential since the ground wire carries away any charge placed on them by the pole. If they are loose, and a small gap of air or insulating corrosion products exists between the staple and the ground wire, the situation is radically different. The staple will be charged to a potential determined by its position on the pole. If this voltage is enough to break down the small gap between the staple and the ground wire, an arc will strike, and discharge the staple. It will take a short time to accumulate charge through the resistance of the wood, but the voltage will build up until the arc is repeated. Our innocent staple has become a source of electromagnetic radiation, interfering with radio and TV reception.

In moist, rainy weather, the gap is bridged by conducting moisture. Gap discharge interference usually quiets down during rainy weather. Corona caused interference usually intensifies during rainy weather. This could be a good first clue.

An exact figure for the percentage of valid RI and TVI complaints on a national basis is not available. An estimate is that about 30% of interference complaints investigated on a well maintained electric utility system are caused by utility owned equipment. This fact should show the progressive utility that eliminating RI and TVI is an important part of their public relations efforts. Prevention comes first and involves education of designers and construction forces; economical location and correction is the second step.

D. ELIMINATION OF RI AND TVI ON NEW CONSTRUCTION

1. Insulators

FPL uses radio-proof primary insulators. These insulators have a conducting glaze over that part of the insulator in contact with the tie wire. This prevents arcs when charging currents flow from the tie wire into the insulator. If a clamp-top is used instead of a tie wire, be sure the clamp is not loose to vibrate. This is especially important if the line grading is such that there is little or no vertical loading or uplift on the conductor. On slack-span dead-ends, use the slack-span dead-end insulator.

Bushings for transformers, capacitors and other equipment must meet ANSI standards for RI and TVI.

Refer to DERM section 2.10.1 as to area described as Salt Spray areas. Subject areas will require upgrading of insulation to 45 kV class post type insulators and copper conductors. All hardware shall be grounded, and the addition of a spill gap insulator assembly to lightning arresters is required. Where silicon carbide arresters have resistive glaze housings, (M&S #334-21701-5); or on a metal oxide arrester with 30 kV housing exist the addition of a spill gap assembly is not required.

In special designs where holes must be bored through the pole or crossarm, specify three inches of wood between bolts and other hardware (more if possible), or bond the hardware together. Double coil spring washers should be used on each end of both bolts supporting primary insulator or hardware on wood poles. A 2-1/4" square washer should be used under any spring washer that would otherwise bear directly on the wood.

2. Conductors

If covered wire (tree wire or covered line wire) is used for primary jumpers, it should be skinned at insulator ties or clamps. This, of course, does not apply to fully insulated, shielded cable nor to fully insulated non-shielded cable operated at 2.4/4.16 kV.

Route conductors to be free of tree contacts or call for tree trimming or removal on the job. Arcs to tree branches will also cause interference.

3. Structures

On all metal structures, specify lock washers or the equivalent under nuts. On wood structures where machine bolts are used, specify double coil spring washers between nuts or bolt heads and flat washers. This will maintain electrical contact when the wood shrinks.

4. Grounding and Other Electrical Connections

Specify the proper connector. If it is aluminum to aluminum or copper to aluminum, specify the use of an inhibitor. Specify Belleville washers on all connections from lugs to flat surfaces, if the connection is aluminum to copper or aluminum to aluminum. See DCS UC-1, Sheet 2.

E. CONSTRUCTION FACTORS

Good construction techniques should result in new distribution facilities free from RI and TVI initially and not prone to develop interference over their lifetime.

Much thought has been given to the prevention of RI and TVI in the development of our overhead and underground distribution standards. Follow these standards for best results.

For emphasis, a few points are listed below:

27. Tighten all connections adequately. Use lock washers or Belleville washers as called for, and tighten them to the proper torque. Excessive tightening on aluminum connections can cause plastic flow, resulting in a loosened connection and trouble later on.

154. On aluminum to aluminum or aluminum to copper connections, clean the conductors and apply inhibitor. Install the connector as specified.

155. For bolts which pass through wood, use double helix spring washers at each end of the bolt to compensate for pole shrinkage. When working on the same pole with existing construction, tighten any nuts which appear loose due to pole shrinkage.

156. Correct or report any conditions, such as broken surge arresters, loose hardware, broken bonds, foreign objects on line, etc., which could cause RI and TVI. Loose hardware is one of the leading causes of interference.

157. When working on a job calling for salt spray construction, be sure all insulators, transformer and capacitor bushings, surge arresters, cutouts, disconnect switches and other primary equipment is of the salt spray type. If not, check with supervision to see if it should be replaced. Severity of known salt spray conditions will have a bearing on this.

158. Keep hardware at least three inches apart or bond it together. This includes bolts which cross each other within three inches inside the pole. It also includes bonding wires, which must not pass within three inches of any non- bonded hardware. (See DCS G-2.0.2.)

159. Tighten any ground wire staples which have worked loose.

160. Report or replace broken or badly chipped insulators.

F. RI AND TVI LOCATING EQUIPMENT

Good equipment makes the job of locating interference less difficult. In general, the equipment should be rugged, portable, and battery operated. The AM radio receiver should have a wide frequency range, or better still, there should be several receivers, each covering a portion of the spectrum. Output indication should be both audible (speaker and headphones) and visible (a meter). It should be possible to switch AGC/AVC in or out. Sensitivity should be variable, with a high degree of sensitivity at the maximum setting. Antennas sensitive to the electric field (whip antenna) and to the magnetic field (directional loop antenna) should be provided. A suggested complement of receivers might include one to cover the AM broadcast band and up to 15 to 20 mHz. If some complaints are coming from CB fans, a good AM CB receiver should be included. Provision should be made for operation on bands which are not active, as measurements will otherwise be interfered with by CB transmissions. A good sensitive AM receiver tunable from 30 mHz upward should be included.

The Radio Operations department within Information Management is charged with the investigation and documentation of RI and TVI concerns and providing that information to Power Systems to perform the repairs. In an effort to become more efficient at locating RI and TVI, Radio Technicians have turned to the latest technology, which includes HF to UHF RFI locators operating in the range of 1.8 to 1000mHz. These new devices have a LCD oscilloscope display with a recording feature. This allows the Radio Technician to record the “noise signature” that the customer is experiencing and then go out and find only the source that is causing the customer’s interference concern. This equipment can be used with an omni antenna and a directional antenna to speed the triangulation and location of the source. Once the source pole is located, a parabolic pin pointer ultrasonic locator is used from the ground to identify the specific component on the pole that is the source. A decision can be made at that time whether to rework the entire pole or to fix just the one source of RI or TVI. Several Radio Technicians have hotstick line sniffers available for crews to use when performing repairs. The sniffer is an RF and ultrasonic locator that enbles the crew to confirm the source from the bucket prior to performing the work. It also allows them to confirm that they have corrected the source of the RI or TVI when they have completed their work.

G. LOCATING RI AND TVI

This section will only give a few general recommendations for the location of RI and TVI. A great deal of field experience is necessary to become proficient at this art.

The first step is to make a good customer contact. Impress on the customer that FPL is interested in locating the interference. Enlist his aid, and if at all possible, listen to the interference on his radio or see it on his TV set. Try to find out when it comes on, goes off, what bands or channels it affects, etc. Sometimes, this will identify the source of interferences, possibly tying it to a piece of customer owned equipment. At any rate, you will know just what it is he is complaining about.

Your locator equipment should be able to cover a wide spectrum of frequencies. See what the frequency spread of the interference is. Attenuation of the line to ground wave is usually greater at the higher frequencies. Use the high frequency setting on your locator equipment to track the interference, as it is usually more localized at the upper limits of frequency. If it extends only up to about 30 megahertz, consider the possibility that it is caused by corona. If it extends considerably above 30 mHz, it is probably caused by a spark discharge.

Some of the more frequently found sources of customer owned equipment causing interference are as follows:

Heating Pad	Fluorescent Lights
Electric Blanket	Door Bell Transformer
Sewing Machine	Electric Fence
Motorized Appliances (Mixers,Defective Radio or TV Set Razors, etc.)	Thermostat in Aquarium
Neon Sign	

Thermostatically controlled heating pads and blankets can be an intense source of interference which covers a whole neighborhood.

The following list covers cases of utility owned causes of interference:

Loose Hardware Noise	Loose Crossarm Bonds
Hi-line Noise (Corona)	Loose Tie Wires
Full Tension & Slack-Span Dead-Ends	Loose Clamp-Tops
Secondary Contacts	Clearance Between Metal
Trees Contacting Primary	Contamination
Lightning Arresters	Broken Insulators

Loose hardware and slack-span dead-ends are two of the more frequent sources of interference caused by utility equipment. To a lesser but significant degree, full tension dead-ends are also sources of interference.

Trouble with slack-span dead-ends using two or more disc strain insulators (JD's) was so prevalent that a special slack-span insulator and clamp was added to our list of standard materials years ago. However, there are thousands of slack-spans in the field made up of two or more JD's linked together with clevis type hardware. The insulators possess a small value of capacitance (in the range of picofarads) and draw small charging currents when energized at line voltage. Oxidation of the zinc coating can take place at the points of contact of the hardware, which puts a nonconducting film in the circuit at each contacting point of the linkage. Line voltage is high enough so that the film is broken down and charging current flows through in the form of an arc. Typical gap discharge type of interference results. This type of interference is corrected temporarily by the insertion of a stainless steel, toothed clip (M&S No. 141-44600-1) between the tongue and the sides of the insulator clevis. A hot stick tool (M&S No. 596-90900-6) is used for the insertion. Earlier versions of this clip and also bronze gun cleaning brushes worked for several years, but interference returned in some cases. It is not known what the effective life of the present clips are. Permanent correction may require changing a slack-span JD dead-end to a slack-span dead-end insulator and clamp. There is at present no permanent correction for full tension dead-end problems.

Loose hardware is usually caused by wood shrinkage. Many of our lines were built before we started using either the flat spring washer or the double helix washer with machine bolts passing through wood.

Wood shrinkage will take the pressure off nuts and bolts. With less friction, they may "back off" and leave a galvanized washer hanging loosely on a galvanized bolt. With a film of zinc oxide in the contact path, a spark discharge may occur between the washer and the machine bolt due to a potential between them created by the primary conductor. This was a frequent occurrence on the spacer nuts and washers on double-arm primary dead-ends.

At one time, our standards called for grounding all pole top pins. Many of these installations still exist, with the ground made on the lower machine bolt. With wood shrinkage, this is a very likely place for a loose connection, resulting in gap discharge interference. With proper safety precautions, removal of the ground wire from the pole top pin and tightening the machine bolts may remove interference from this source. Caution: Do not remove ground in salt contaminated areas; tighten connection.

The following comments on procedures to locate interference will be found superfluous to those persons who have had even a little experience in interference work. They are included because they may be of help in the case of a beginner.

If identification of probable source cannot be made by listening to the complainant's set, turn on your car mounted equipment and tune in. With the highest frequency setting at which a good signal is received, move your receiver along the line to try and establish the source. The following points must be remembered.

1. There will be standing waves of the radio frequency interference signal on the line. Many peaks and nodes will be found. The peaks should become more intense near the source.

161. Distance from the line affects the signal greatly. Passing under a lateral while riding along the line will cause a peak. Look for any of the causes of interference previously mentioned. A sharp eye will probably allow you to "home in" on as many interference sources as your equipment will.

162. Interference from thermostatically operated heating pads, electric blankets, demand meter contacts, etc., usually comes at fairly regular intervals. It is usually a damped wave of sound; very intense at first, but immediately decreasing to zero.

163. Remember that loose connections in a current carrying power circuit can cause severe interference, but usually the other effects, such as flickering lights, or heating cause them to be located quickly. You will seldom find them the cause you are looking for. An exception to this might be a burned-up fuse tube on a capacitor bank.

164. Sometimes the only cure for interference in a salt contaminated area during a long dry spell is a good rain.

165. Surge arresters which have the ground lead blown off by the ground lead disconnector may also have sustained cracks in the body. Have them replaced with new Polymer arresters to restore surge protection and to eliminate a possible source of interference.

166. Look for loose ground connections, loose staples on pole ground wire, broken wire with ends loosely touching.

167. When you have completed your investigation and corrected the trouble, tell the customer and have him check his reception to be sure you have indeed removed the interference.

H. OTHER REFERENCES

1. IEEE Standard Methods for Measuring Electromagnetic Field Strength for Frequencies Below 1000 mHz in Radio Wave Propagation, IEEE Standard No. 302, August 1969.

2. IEEE TUTORIAL COURSE TEXT. 76 CH1163-5-PWR "The Location, Correction and Prevention of RI and TVI SOURCES FROM OVERHEAD POWER LINES". Price $10.00 Available from IEEE SERVICE CENTER, Single Publication Sales Dept., Piscataway, N.J., 08854.

2.9.4 ELECTROMAGNETIC FIELDS

A. GENERAL

1. Introduction

Some scientific studies have suggested the possibility of adverse health effects from magnetic fields under certain circumstances. In addition, the quality of the picture on computer monitors and other video display screens can be affected by magnetic fields. Electric facilities such as service conductors, padmount transformers, equipment in vaults and mats, as well as customer owned service facilities are all sources of magnetic fields that may affect occupied spaces. The following guidelines should therefore be considered when designing new services, or rebuilding or reworking FPL facilities.

2. Theory

- All conductors carrying current create magnetic fields
- Fields from adjacent conductors for different phases tend to cancel each other.
- Fields from multi conductor circuits drop off with the square of the distance.
- A field from a single conductor drops off linearly with distance.
- A magnetic field can cause the picture on a cathode ray tube type computer monitor or television to vibrate.
- In general, the larger the viewing area of the computer monitor, the smaller the field required to cause interference.

3. Reducing Magnetic Fields

- Fields can be reduced by reducing spacing between phase, neutral, and grounding conductors.
- Increasing the distance from the source reduces magnetic fields.
- In specific situations, the field may be directed to another location with certain types of shielding materials.

B. GENERAL TECHNIQUES TO MINIMIZE EMF

Consideration should include potential effects on computers and other electronic equipment by both FPL and the customer during the initial stages of design. During initial negotiations the customer may be helped to understand the potential interference that might result from a design which locates computers, computer displays, and other electronic equipment near areas where electro-magnetic fields may be present. Costs to the customer for shielding adjacent interior walls can be very high should the magnetic field generated cause interference with the picture.

1. Customer's Building Plan Considerations

- Increasing the distance between electric facilities and occupied spaces
- Assuring loads are balanced between phases
- Providing vault/mat locations that are adjacent to hallways, elevators, parking spaces, or other areas that do not typically contain computers and other electronic equipment
- Designing the electrical room so that the bus stub, bus bars and secondary cable are not on a wall (or the ceiling) that is adjacent to an occupied space.
- Locating meter rooms, and areas with step-down transformers and/or electrical switchgear, away from spaces that normally contain computer equipment and electronics

2. FPL Designer Considerations

a. Overhead Installations

- Locate facilities as far away as reasonable from occupied spaces
- Minimize conductor spacing
- Use triplex secondary cables
- Locate transformers at lease 10’ (feet) from occupied dwellings when reasonably practical

b. URD Installations

- Cable Location

1. The cable route to the building should be as perpendicular to the building as is practical and reasonable.
2. If a cable must be run parallel to the side of a building, try to keep the cable at least 10’ (feet) from the side of the building when reasonably practical.

- Padmount Transformer location

1. Locate at least 10’ (feet) from occupied dwellings when practical and reasonable.
2. Turn secondary side away from building.

c. Vaults and Mats

- Vault/Mat Location

1. Where practical, locate so adjoining walls, ceiling and floor areas are not occupied spaces.

- Cable Location

1. Maintain as much clearance as practical and reasonable from ceiling and walls adjacent to occupied spaces.
2. Keep conductors bundled together
3. Bundle neutral and ground conductors with other secondary conductors
4. Minimize cable length

- Bus Bar and Bus Stubs

1. The customer’s bus stub and any FPL collector bus should be located as far away as practical from walls/ceiling adjacent to occupied spaces. If any wall is an exterior wall, the bus stub should be located as close to this exterior wall as practical while maintaining proper clearances. Where more than one bus stub is served, work with these guidelines while maintaining the spacing shown in DCS UC-12.0.0.
2. Minimize spacing.

- Transformers

1. Locate as far as reasonable from occupied areas
2. Route ground bonds with secondary neutral and phase cables from transformer to the neutral connections of customer then from there to ring bond.

- Phase configuration

1. This is a technique where, as a result of maintaining the three phases and neutral of the secondary cables from the transformer to the collector bus bundled together, a practical cancellation or reduction

in the magnetic field results, as compared to the individual phases being racked separately. Therefore, rack or spool secondary cables together wherever practicable. Also when practical, rack the neutral and grounding conductor with the hot legs, as the neutral and ground carry the current imbalance of the phases. When the vault is made up of three aerial transformers, the neutral conductors should also be racked with their corresponding phase conductor from the transformer to the collector bus, and then all secondary conductors racked together if practical.